Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

Darcy L. Endo-Omoto
Vice President
Government & Community Affairs

July 13, 2009

The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
Kekuanaoa Building, 1st Floor
465 South King Street
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2008-0274 – Decoupling Proceeding
Questions from Panel Hearings Held on June 29 to July 1, 2009

On July 1, 2009, during the decoupling panel hearings held on June 29 to July 1, 2009, the Commission issued PUC Hrg. Ex. 1 which asks specific questions regarding the HECO Companies' response to PUC-IR-14.[1] The responses to these questions are provided in Attachments 1 and 2.

During the hearings the Commission verbally asked the Companies questions regarding the Consumer Advocate's and the HECO Companies' Joint Final Statement of Position, filed on May 11, 2009, as revised on June 25, 2009, and also asked for written clarification of the Companies' positions and testimony made during the hearings. The following responds to these requests:

1. What can the Commission do to help improve the Companies' financial health?

Response: In general, there are four themes that are important to improving the Companies, financial health:

1. Reasonable assurance that costs incurred to provide service to ratepayers are paid for through the rates paid by ratepayers
2. Timely recovery of those costs incurred to provide service to ratepayers
3. Regulatory support that aligns incentives with policies
4. Reducing regulatory uncertainty – which is directly related to the previous three points above.

[1] The "HECO Companies" or "Companies" are Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc. and Maui Electric Company, Limited.

The Companies require a realistic opportunity to earn the return reasonably determined to be fair.

A fair return must:
(1) be commensurate with returns on investment in other enterprises having corresponding risks and uncertainties;
(2) provide a return sufficient to cover the capital costs of the business, including service on the debt and dividends on the stock; and
(3) provide a return sufficient to assure confidence in the financial integrity of the enterprise to maintain its credit and capital-attracting ability.

For example, HECO has not been able to earn its allowed return in recent history. Below is a summary of the HECO's recent returns[2]:

	Return on Rate Base	Return on Common Equity
2005	6.20%	6.92%
2006	6.78%	7.61%
2007	4.92%	4.52%
2008	7.05%	8.07%
2009 1st Qtr	6.42%	7.32%

The returns that HECO have actually earned have been substantially lower than those used to establish rates in its recent rate cases for a number of reasons.

Structural Lag

First, although interim rate orders in HECO's most recent rate cases generally have been issued within the time frames set by law, the lag between the start of the test year and the interim rate relief has not allowed HECO the opportunity to actually earn the allowed return in the test year. This is due in part to the timing of the filing of the rate case applications by HECO. However, even if the Company were to file its rate case at the earliest possible time allowed under the Commission's rules (as it has done in the HECO 2009 rate case rate case Docket No. 2008-0083), six months prior to the start of the test year, the statutory deadline for an interim decision would be May at the earliest (and June if the evidentiary hearing has not been held). Because of this structural lag, it would be difficult for the Company to achieve its authorized return in the test year even if it were to file its rate case application at the earliest allowed date. Under the test year concept, the amount of the rate increase approved by the Commission in a general rate case, which uses an average rate base, generally is the increase in revenues necessary at the beginning of the test year. Unless a rate increase is effective at the beginning of a test year, the utility will not have an opportunity to

[2] Interim and final rates in HECO's 2005 test year rate case (Docket No. 04-0113) were based on a 8.66% rate of return on rate base ("ROR") and a 10.7% rate of return on common equity ("ROE"). Interim rates in HECO's 2007 test year rate case (Docket No. 2006-0386) were based on a 8.62% ROR and 10.7% ROE.

earn the fair rate of return on rate base determined to be fair and reasonable by the Commission, based on the estimated results of operations for the normalized test year. If the rate increase is received later in the test year, the amount of the rate relief actually received in the test year will be proportionately lower than that determined to be necessary.[3]

HRS §269-16(d) does not require a decision in nine months; it simply requires that the PUC "make every effort to complete its deliberations and issue its decision as expeditiously as possible and before nine months from the date the public utility filed its completed application; provided that in carrying out this mandate, the [PUC] shall require all parties to a proceeding to comply strictly with procedural time schedules that it establishes." If a decision is rendered after the nine-month period, the PUC "shall report in writing the reasons therefore to the legislature within thirty days after rendering the decision." The schedules agreed to by the parties invariably require more time, due to the time required for the pre-discovery phase (public hearings, motions to intervene), discovery phase (information requests and filed testimonies), hearing phase, briefing phase, and decision phase.

Accordingly, July 1st is the earliest date the Companies may file for a test year (without a waiver) that runs from January 1 through December 31 of the following year. Typically, that means that a rate increase is not authorized until well into the test year.

HAR §6-61-87(4):"...The test year shall be a forward test year, determined as follows:

(A) If an application is filed within the first six months of any year, the test year shall be from July 1 of the same year through June 30 of the following year; or

(B) If an application is filed within the last six months of any year, the test year shall be from January 1 through December 31 of the following year;"

HAR §6-61-92 allows PUC to modify the HAR §6-61-87(4) requirement if it "would impose a financial hardship on the applicant or be unjust or unreasonable." The

[3] It may be worthwhile for the Companies to propose and for the Commission to consider the possibility of revising the Commission's rules to advance the allowable date to file a general rate increase application so that there is consistency between that time frame and the statutory deadline for issuance of an interim decision. Without such a structural change to the rate case process, it would be difficult for a utility to obtain interim rate relief by the beginning of the test year and to achieve a fair return on its utility property in the test year.

Even though interim rate orders allow cash flow to come to the Company during the period leading up to the final decision, the fact that a refund could be ordered with interest creates a degree of unease among the rating agencies and investors. Accordingly, since a statutory deadline exists for interim rate orders but not final decisions, Commission issuance of both interim and final orders as expeditiously as is feasible would help to allay investor uncertainty that can have a negative impact on HECO's cost of capital.

Companies have previously received test year waiver requests granted for the early filing of rate increase applications.[4]

Actual kilowatthour sales lower than sales forecast per the rate case

Second, kilowatthour sales were lower than forecast in the rate cases, resulting in insufficient revenue dollars, which deteriorated returns. Beginning after 2004, sales growth has reversed into sales decline, and fixed costs recovered through rate components that vary with usage are not recovered until rate increases can be implemented.

Actual sales for HECO in both 2005 and 2006 were less than the sales assumed in the 2005 rate case. Additionally, actual sales in 2007 and 2008 were less than the sales assumed in the 2007 rate case. And finally, 2009 sales are projected to be less than the sales assumed in the 2009 rate case.

O&M Cost increases

Third, costs are increasing faster than the revenues received to pay for those costs. For example, in 2006 HECO received a full year of the 2005 test year interim rate increase, but still was unable to achieve its authorized returns. Likewise, in 2008, the Company had a full year of the 2007 test year interim rate increase, but faced higher O&M than what was included in the test year revenue requirement. As long as cost increases outpace sales growth and revenues are based on sales, the Company will be in an endless cycle of catch-up, struggling to achieve a fair return on its utility property.

The following are essential for HECO to actually have a realistic opportunity to earn a fair and reasonable return:

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[4] Examples of test year waivers granted for early filing of an application:

- Order No. 16031, issued October 20, 1997, in the 1999 MECO Rate Case (Docket No. 97-0346)
  - Approval based on:
    - Anticipated completion of the Maalaea Unit M17 in November 1998
    - Increased O&M and depreciation expenses
    - Very low sales growth
  - MECO filed its application on January 9, 1998, and PUC issued an interim decision on December 28, 1998
  - The final order, Amended D&O 16922, was issued on April 6, 1999
- Order No. 12804, issued November 4, 1993 in the 1995 HECO Rate Case (Docket No. 7766)
  - Approval based on:
    - Large amount of capital projects that were anticipated to be completed in 1994 and 1995
    - High depreciation and O&M expense growth than historically experienced
    - Higher payments to IPPs for non-fuel components of energy charges that were not recovered through ECAC.
  - HECO filed its application on December 27, 1993 and the PUC issued its interim decision on December 20, 1994.
  - Final D&O 14412 issued on December 11, 1995

(1) Rate relief allowed in the HECO Companies' periodic rate cases should be both adequate and timely. To be adequate, test year revenue requirements must fully reflect test year costs, as adjusted to account for known and measurable changes in the way the Company does business. To be timely, rate relief must be timed to coincide when cost increases incur.
(2) The HECO Companies should be allowed to continue to flow through changes in fuel and purchased energy costs through its ECAC.

Mechanisms that allow the HECO Companies to begin recovering substantial new or increased costs that occur between rate cases need to be implemented.

The Companies currently faces rapidly rising O&M costs and rising capital expenditures. It is essential that cost recovery be aligned with cost incurrence if the Companies are to have a realistic opportunity to actually earn the return found to be fair by the Commission, because sales are not growing and therefore cannot offset the increases in costs. If traditional rate cases do not allow cost recovery to keep up with cost increases, then new mechanisms need to be developed.

Rate Base Increases

Fourth, under traditional ratemaking, utilities have to wait for rate cases to be processed to begin recovering costs incurred to install new infrastructure, which means there can be a substantial lag in recovering costs, and even substantial cost under-recovery - which can result in credit degradation and a higher cost of capital. The later in the test year that the increase is received, the lower will be the amount of the increase actually received in the test year. In simple terms, if an annual increase of $50 million is awarded after one-half of the test year has passed (which is the earliest that the interim increase could be made effective), then only approximately one-half of the increase (or $25 million) will actually be received in the test year.

To help address these issues, traditional ratemaking should be supplemented with other ratemaking tools, such as mechanisms that allow cost recovery to begin as soon as new facilities go into service.

A number of alternative ratemaking structures have previously been implemented In order to better time cost recovery with cost incurrence.

Alternative Ratemaking Structures

End of Year Rate Base Proposals. This involves a deliberate mismatch of average sales and expenses with end of year rate base. It has been adopted for test years that reflect large capital expenditures (i.e., large differences between average and end of year rate base). The Commission has previously approved end of year rate base proposals.

Two Year Test Year Period. A Two-Year Test Year Period supports "phased"/"step" relief extending over two years due to successive events that will occur in such years. This mechanism requires budget projections up to 2 years in advance. In addition, this mechanism requires Commission approval to use a two year test year period. The Commission has previously approved two year test period waiver requests.

Step Increases. This mechanism is intended to time cost recovery with significant expenses or changes in rate base. Step increases have been implemented for capital projects[5], power purchase agreements[6], and other expenses (e.g., wage increases, OPEB). This mechanism generally involves the use of annualized costs and benefits. The step increase in rates reflects the impact of the significant expense or change in rate base when it does go into effect or service and customers receive the benefits of the significant expense/capital project.

The HECO Companies have proposed mechanisms to better time cost recovery with cost incurrence, while allowing for reasonable customer protections and regulatory review. The Consumer Advocate agreed to the proposed mechanisms discussed below.

Decoupling

The Joint Decoupling Proposal filed in the "Joint Final Statement of Position of The HECO Companies and Consumer Advocate" on May 11, 2009, includes a sales

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[5] The Commission has recognized the appropriateness of including the full costs associated with major generating unit and transmission line additions in the test year results of operations. Accounting for the full costs in this manner will allow the utility the opportunity to earn a reasonable rate of return on the total investment in its major generation project, from the time it goes into service. In MECO Docket No. 7000, which utilized a 1993 test year as well as a 1992 test year, the Commission authorized two step increases in 1993 (timed to coincide with the addition of the units to MECO's system) based on the annual costs and benefits of adding M16 and M15 to MECO's system. The annual costs included depreciation expenses. (The impact of the adjustment to include the full costs of these generating units on revenue requirements was offset to some extent in the final decision and order by recognizing annual sales and revenues (net of fuel expense) for new customers added in 1993.) In Docket No. 7766, which utilized a 1995 test year, the Commission authorized, on an interim basis, a step increase in August 1995 based on the annual costs of adding the Waiau-CIP transmission lines to HECO's system.

[6] The Commission approved the use of step increases for purchase power agreement capacity costs, based on the full annual costs of such PPAs. In Docket No. 6531, which utilized a 1990 test year, the Commission authorized the inclusion of the annual costs and benefits associated with the Kalaeloa Partners, L.P. ("Kalaeloa") PPA (by which HECO added 180 MW to its system) in revenue requirements, and a step increase based on the annual costs and benefits, even though the Kalaeloa facility went into commercial operation five months after the conclusion of the 1990 test year.

In Docket No. 6998, which utilized a 1992 test year, the Commission authorized a step increase in September 1992 for HECO's PPA with AES Barbers Point, Inc. ("AES-BP", now known as AES Hawaii, Inc.), by which HECO added another 180 MW to its system. The 1992 test year revenue requirements in Docket No. 6998 included the annual costs and benefits for the AES-BP PPA, even though AES-BP went into commercial operation in September 1992.

decoupling mechanism, which will be implemented through a Revenue Balancing Account ("RBA"), and a Revenue Adjustment Mechanism ("RAM"). The purpose of the sales decoupling mechanism is to remove the linkage between utility sales and revenues, in order to encourage energy efficiency. The purpose of the RAM is to adjust revenues (which are decoupled from sales) to reflect changes in revenue requirements between rate cases related to increases in cost due, for example, to inflation and to continued investment in infrastructure necessary to maintain service reliability.

Purchased Power Adjustment Clause

As proposed in the HECO 2009 rate case (Docket No. 2008-0083), a separate clause which would allow the Company to pass through all reasonably incurred purchased power agreement costs including all capacity, O&M, and other non-energy payments approved by the Commission (including those acquired under the feed-in tariff) and it would either decrease the Company's risk profile or increase the Company's borrowing capacity or some combination, thereof. The greater the certainty of cost recovery, the more positive the impact on the Company's risk profile. Recovery through a cost recovery mechanism will reduce cost recovery risk, but will not eliminate it, since there would always be a risk of future changes to a recovery mechanism. Reduced risks could result in lower return requirements to investors.

Rating agencies are aware of the Companies' large purchased power obligations. S&P states in its November 28, 2008 Summary report:

> The consolidated financial profile is 'aggressive', reflecting in part the very heavy debt imputation Standard & Poor's Ratings Services applies to HECO for its long-term power purchase agreements (PPAs). These obligations added about $469 million in on-balance-sheet debt 2007 and about $568 million beginning in March 2008 and reflect evergreening of PPA obligations. (Consistent with our published criteria, we assume that expiring PPA contracts are replaced with new ones at similar terms.) While we apply significant debt obligations to HECO, we also recognize the historical reasons that have led to HECO buying a substantial amount of its power supply from third-party suppliers and that the regulatory recovery of capacity costs associated with these contracts has been supportive.

REIP/CEI Surcharge

Establishment of an REIP/CEI Surcharge to expedite cost recovery of infrastructure that supports greater use of renewable energy or utility grid efficiency. The proposed REIP/CEI Surcharge also would be used to recover costs that would normally be expensed in the year incurred and to recover costs stranded by clean energy initiatives, subject to the Commission's prior approval.

The Companies need to raise additional funds for renewable infrastructure capital and deferred software development projects, while still continuing to make other investments required to maintain the reliability of the existing system. The Company's current capital expenditure budget is already significant given the aging infrastructure. The REIP/CEI Surcharge demonstrates timely ability to earn on and recover clean energy investment and expenses which is supportive of credit quality.

The HECO Companies need to be able to raise the capital in the financial markets to construct and install these infrastructure projects without degrading credit quality, or increasing the cost of capital, either of which would be detrimental to ratepayers and the development of third-party renewable energy projects. The REIP/CEI Surcharge will demonstrate regulatory support and result in more immediate cost recovery which could reduce investors' perceptions of risk (although the HECO Companies would still need to raise the capital in the first place). This may help to maintain credit quality and cost of capital, and mitigate the potential degradation in credit quality caused by increasing capital requirements.

S&P addressed electric utilities' rising capital expenditures. For example, in a report dated March 9, 2009, S&P cautioned that, "Slow recovery of costs could further impinge on its liquidity as short-term funds are consumed to finance high working-capital needs." The report added that:

"In addition to fuel-cost recovery filings, regulators likely will have to be addressing significant rate increase requests related to new large generating capacity additions, infrastructure and reliability upgrades, and environmental modifications. Current cash recovery and/or return by means of construction work in progress may mitigate the significant cash flow drain and reduce the utility's need to issue debt securities during the construction cycle." and "To the extent that utilities increase their capital budgets to address these needs, they will be highly dependent on electricity rate increases to sustain bondholder protection measures."

The HECO Companies will also be addressing the question of "what can the Commission do to help the Companies improve their financial health" in their post hearing written briefs.

2. Table 6, page 8, NRRI Scoping Paper: Is decoupling a disincentive to energy efficiency by reducing payback periods for energy conservation measures?

Response: Please refer to Attachment 3.

3. Please explain the Companies' response to question 1 of NRRI's Scoping Paper, Appendix 2 that states that the HECO Companies recover approximately 90% of their fixed costs through volumetric rates.

Response: Please refer to Attachment 4 which describes the review undertaken by the Companies and the Department of Business Economic Development and Tourism ("DBEDT") regarding the percentage of fixed costs recovered through the Companies' volumetric rates.

4. What other costs decrease with sales besides fuel and purchased power expenses?

Response: In its response to DBEDT's question posed during the decoupling panel hearings, the HECO Companies acknowledged that there are certain production O&M expenses that are related to sales levels, such as expenses for chemicals and water. However, these expenses are relatively small, especially in comparison to fuel and purchased power energy expenses. To illustrate the relative magnitude of these production O&M expenses related to sales levels, the HECO Companies provided to the DBEDT the avoided energy cost rates for September 1, 2008 and June 1, 2009 that the HECO Companies filed with the Commission, as required by the decision and order in Docket No. 7310. These filings for HECO, HELCO, MECO Maui, Lanai, and Molokai Divisions are provided in Attachment 5. The line item "(2) Avoided O&M Cost" provides an estimate of those production O&M expenses that are related to sales levels. While the Avoided O&M Cost changes from year to year, it is small in comparison to the total avoided energy cost rate; similarly it is small in comparison to total fuel and purchased energy expenses.

5. How will the RAM revenues be accounted for in the RBA/RAM process?

Response: Based on the Joint Final Statement of Position, the Company would submit its annual RAM filing by March 31 of each year. The RAM filing would include the proposed target revenues for the year, based on the rate adjustment mechanism described in the proposed tariff. Thereafter, the Consumer Advocate and Commission would have 60 days to review the annual RAM filing, and tariffs based on the filing would become effective on June 1 of the year.

Because this mechanism is new, initially the new target revenues for the year would be established upon the completion of the review period (June 1). While described as an automatic adjustment mechanism, as a new mechanism, until the review period is completed, there is uncertainty that the proposed target revenues will be the revised target revenues for the year (revenues adjusted for the RAM filing), until it has been reviewed.

After the review period has elapsed (and adjustments to the RAM filing, if any, are made), the new target revenues have been established, and the collectability of the revised target revenue becomes certain. At that point, the HECO Companies would begin to accrue the difference between the revised target revenues and the actual revenues through the end of May, based on the monthly allocation of target revenues.

This is different from other automatic adjustment clauses, as this is a new mechanism and there is an explicit period in the tariff for review of the filing by the Commission and Consumer Advocate before it becomes effective.[7] Thus there would be a lag in the revenues for the first five months of the year, at which time we would accrue the revenues to "catch-up" to the target revenues allocated through May. Thereafter, revenues would accrue based on the target revenues based on the monthly allocation factors.

6. What is in the HECO Companies' proposed inclining block rate design for schedule R customers?

Response: The inclining block rate design is proposed and stipulated to for residential customers in the current open rate cases: HECO test year 2007 and test year 2009; HELCO test year 2006; and MECO test year 2007. The proposed inclining block designs for the HECO Companies' Schedule R rates have the following common design elements: 1) each have three usage blocks; 2) the usage blocks differ in price by about 1 cent per kWh; and 3) the highest 10% of usage is targeted by the highest or "tail" block. These proposed rate designs will be implemented if approved by the Commission in their respective rate cases. Although the response of residential customers to the implementation of inclining block rates is not known, to the extent that reduced kWh sales are anticipated from the higher priced blocks, the potential reduction in fixed cost recovery due to reduced sales can be higher under a residential pricing regime of inclining block rates than under the traditional residential rate design that has a single average rate.

7. Please correct the arithmetic errors in the response to PUC-IR-43.

Response: Please see Attachment 6, which is the revised Attachment 2 to the HECO Companies' response to PUC-IR-43 .

8. If the rate base RAM is calculated based on major projects that may have costs that are disallowed in a rate case after its implementation, how does the proposed RAM tariff address this situation?

Response: Please see Attachment 7 which is the revised draft RAM provision tariff that states that RAM revenues (including interest) associated with major capital

[7] If after the RAM mechanism has been in place for a period of time, and the review process does not result in adjustments, there may be a basis to conclude that there is certainty that the revised proposed target revenues at the time of the RAM filing will be collected, and accrual of the target revenues allocated through March 31 could be accrued at that time.

projects' costs that are disallowed by the Commission will be refunded to customers (see highlighted language). The Consumer Advocate has concurred with this revised draft of the RAM provision. Beginning with their March 30, 2009, "Joint Proposal on Decoupling and Statement of Position of the HECO Companies and the Consumer Advocate" through their last submittal of the "Revised and New Exhibits for the Joint SOP" filed in a letter to the Commission on June 25, 2009, the Consumer Advocate and the Companies have reflected their agreement to refund RAM amounts (including interest) collected prior to the Commission's review of the major projects to the extent that these costs are disallowed (see Exhibit C, Section V, Item D, "Significant/Major Projects".) Unfortunately, the description of this agreement had inadvertently been overlooked for inclusion in the RAM tariff previously.

9. How will the Companies address the issue of outages and the target revenues?

Response: Please see Attachment 8.

The HECO Companies thank the Commission for this opportunity to clarify their testimony and address the Commission's concerns regarding the decoupling proposal.

Sincerely,

for Darcy L. Endo-Omoto
Vice President
Hawaiian Electric Company, Inc.
Hawaii Electric Light Company, Inc.
Maui Electric Company, Limited

Enclosures

cc: Division of Consumer Advocacy
Hawaii Renewable Energy Alliance
Haiku Design and Analysis
Hawaii Holdings, LLC, dba First Wind Hawaii
Department of Business, Economic Development, and Tourism
Hawaii Solar Energy Association
Blue Planet Foundation

HECO Companies' Responses to:
Commission Questions to the Companies-July 1, 2009
PUC Hearing Exhibit 1

1 (a):

Please see Attachment 1.(a) to this response, column C, for the sales foregone under the HECO Companies' decoupling proposed in the absence of a RAM. In the HECO Companies' response to PUC-IR-14, Attachment 1, as revised on June 29, 2009, on sheets 1, 5, and 9, line 4 for each Company, respectively, net revenues are estimated assuming that sales decoupling is in place beginning at July 1, 2009 for HECO, at October 1, 2010 for HELCO, and at July 1, 2010 for MECO. On sheet 2, 6, and 10, line 4 for each Company, respectively, net revenues are estimated assuming that there is no sales decoupling and no RAM. For each of the HECO Companies, on sheets 1 and 2, 5 and 6, 9 and 10, the same assumption for rate case timing is used. The difference between the line 4 values on sheets 1 and 2, 5 and 6, 9 and 10, represents the value of the revenue foregone due to sales decoupling, as shown in Attachment 1.(a) to this response.

For all HECO Companies, for years 2011 through 2013, the revenue foregone each year is related to forecasted year over year sales increases, as shown in Attachment 1.(a) to this response. For the year 2010, HECO[1] and HELCO show a sales decoupling impact subsequent to implementation of a final decision in a test year 2009 rate case and an interim decision in a test year 2010 rate case, respectively. For the year 2010, the MECO calculations assume that actual sales equal test year sales and no sales decoupling impact is expected.

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[1] In HECO's scenario without RAM and no sales decoupling, the ROE used is 11.25% for 2010 versus a ROE of 11.00% for the scenario with RAM. This assumption is consistent with the Company's Rebuttal Testimony filed May 22, 2009, Docket No. 2008-0083. This resulted in HECO's 2010 net revenue number to differ between these two scenarios.

1(b):
Please see Attachment 1.(b) to this response, column E, for the ratio of the RAM to sales foregone as illustrated in the HECO Companies' response to PUC-IR-14, filed on June 29, 2009. Column F reflects the estimated ROEs of the Companies with sales decoupling and the RAM for the same period of 2010 through 2013. Based on this analysis, none of the Companies would earn their authorized ROE levels, which is 10.70%[2] (see Attachment 2 to this response) even if the RAM is implemented.

1(c):
Please see Attachment 1.(c) to this response which calculates the HECO Companies' sales foregone for the years 2005 through 2008, which assumes that for all the Companies, 2004 is a "base" year for net revenues, i.e., earning at authorized ROEs. In column B of Attachment 1.(c) to this response, the Companies' revenue targets are calculated using the last authorized revenue requirement (less fuel and purchased power expenses, grossed up for revenue taxes). The calculation of the annualized net revenues for the test years are shown on WP 1.(c).1 to this response.

The implementation of these net revenue targets are assumed to take place at the time the Commission orders either the final or the interim decisions and orders in the rate cases. The only exception is the Final Decision & Order issued in HECO's 2005 rate case (Docket No. 2004-0113). In this analysis, the target revenue based on the Final Decision & Order is reflected on the date that the Interim Decision & Order was issued. Thus, the analysis reflects no revision to the target revenues due to the difference between the revenues authorized by the Commission in

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[2] HECO 2007 test year rate case, interim D&O No. 23749 filed October 22, 2007, Docket No. 06-0386. HELCO 2006 test year rate case, interim D&O No. 23342 filed April 4, 2007, Docket No. 05-0315. MECO 2007 test year rate case, interim D&O No. 23926 filed December 21, 2007, Docket No. 06-0387.

its Interim and Final Decision & Orders. Dates that the decision and orders were issued are also found on WP 1.(c).1 to this response.

The O&M and rate base RAM calculations for the Companies are found in WP 1.(c) 2 for HECO, WP 1.(c) 3 for HELCO, and WP 1.(c) 4 for MECO to this response. The calculations for the RAMs are based on the methodologies proposed and illustrated in the revised Joint Final Statement of Position, Exhibit C, Attachment 6, filed on June 25, 2009. The O&M and rate base RAM estimates developed for this response were developed solely by the HECO Companies and have not been reviewed and concurred to by the Consumer Advocate.

The periods that the RAMs and target revenues from preceding rate case decisions and orders are assumed to be in place during the 2004 through 2008 period are also based on the Companies' and Consumer Advocate's Joint Final Proposal, as reflected in Exhibits C, filed on June 25, 2009, and Exhibit C, Attachments 1 and 2, filed on May 11, 2009.

The sales foregone are shown in column D of Attachment 1.(c) to this response and are calculated as the difference between the recorded revenues (shown in column C of Attachment 1.(c) to this response) and the target net revenues based on having sales decoupling only (shown in column B of Attachment 1.(c) to this response). Column A, Sales Decoupling and RAM, is provided to compare what the net target revenues would have been if the RAM had also been approved and implemented during the 2004 through 2008 time period.

2: Attachment 2 to this response provides the five-year simple average ROEs for HECO, HELCO, and MECO, respectively (confidential information). As this financial information for future years is nonpublic information that should not be disclosed publicly as it might trigger requirements under the rules and guidelines of the Securities and Exchange Commission and/or the New York Stock Exchange that information that would be meaningful to investors be released to all investors, if the information is disclosed beyond a limited number of "insiders" (including persons required by agreement to maintain the confidentiality of the information and to use it only for proper purposes), it is being filed under the Protective Order issued on January 9, 2009 in this proceeding. If this attachment is not filed under the Protective Order in this proceeding, the disclosure of nonpublic financial information might trigger disclosure requirements under the rules and regulations of the Securities and Exchange Commission and/or the New York Stock Exchange. Because this information is confidential, a table showing the differences between Scenario 1 and the other scenarios is provided in Attachment 2.

The dates assumed for rate cases for the three scenarios were provided in the Companies' revised response to PUC-IR-14, filed June 29, 2009, on page 5, 7, and footnotes 3, 5, and 6. These assumptions are summarized in the table below.

Company	Scenario	2009	2010	2011	2012	2013
HECO	1. w/RAM	Jul 2	RAM	Jul 1	RAM	RAM
	2. w/o RAM same cycle	Jul 2		Jul 1		
	3. w/o RAM more freq RC	Jul 2	Jul 1		Jul 1	
	4. RPC w/reset	Jul 2	RAM	Jul 1	RAM	RAM
	5. RPC w/o reset	Jul 2	RAM	Jul 1	RAM	RAM
HELCO	1. w/RAM		Oct 1	RAM	RAM	Jul 1
	2. w/o RAM same cycle		Oct 1			Jul 1
	3. w/o RAM more freq RC		Oct 1		Jul 1	
	4. RPC w/reset		Oct 1	RAM	RAM	Jul 1
	5. RPC w/o reset		Oct 1	RAM	RAM	Jul 1
MECO	1. w/RAM		Jul 1	RAM	Jul 1	RAM
	2. w/o RAM same cycle		Jul 1		Jul 1	
	3. w/o RAM more freq RC		Jul 1		Jul 1	
	4. RPC w/reset		Jul 1	RAM	Jul 1	RAM
	5. RPC w/o reset		Jul 1	RAM	Jul 1	RAM

The above table reflects the assumed interim decision and order dates granting the interim rate reliefs in the test years. To simplify the calculations, the awards authorized by the Commission in its interim decision and orders were assumed to be the same as the award authorized in its final decision and orders.

The Companies' currently proposed ROEs are described below. For HECO, the proposed ROE is 11.0% (with approval of the RAM) and 11.25% (without approval of the RAM). Further discussion regarding HECO's proposed ROEs may be found in HECO RT-19, filed in HECO's 2009 test year rate case, Docket No. 2008-0083, filed on May 22, 2009. HELCO's and MECO's proposed ROEs of 10.7% were authorized in the Commission's Interim Decision and Order No. 23342, filed April 4, 2007, in Docket No. 05-0315 (HELCO's 2006 test year rate case) and in Interim Decision and Order No. 23926, filed December 21, 2007, Docket No. 06-0387 (MECO 2007 test year rate case). Both HELCO's and MECO's ROEs were agreed upon by all the parties in their respective rate case proceedings.

Decoupling Docket
Hearing Exhibit - Question 1.(a)

PUC-IR-14 Response - Attachment 1 (Amounts in Thousands)	Net Revenues Sheets 1, 5, 9 (Line 4) A	Net Revenues Sheets 2, 6, 10 (Line 4) B	Sales Foregone (B-A) C	Sales gWh Sheets 1, 5, 9 (below notes) D	% Change in Sales gWh E = D/Prev D - 1
Hawaiian Electric Company					
For Year: 2010	$527,404	$529,277 [1]	$1,873	7,464.5	
For Year: 2011	$559,341	$563,124	$3,783	7,505.8	0.6%
For Year: 2012	$588,709	$598,003	$9,294	7,608.4	1.4%
For Year: 2013	$589,976	$606,223	$16,247	7,727.1	1.6%
Hawaii Electric Light Company					
For Year: 2010	$147,721	$148,427	$706	1,122.6	
For Year: 2011	$171,625	$174,259	$2,634	1,136.4	1.2%
For Year: 2012	$171,625	$177,586	$5,961	1,154.0	1.5%
For Year: 2013	$182,879	$187,526	$4,647	1,175.1	1.8%
Maui Electric Company					
For Year: 2010	$142,760	$142,760	$0	1,227.4	
For Year: 2011	$155,943	$159,902	$3,959	1,257.5	2.5%
For Year: 2012	$165,869	$168,121	$2,252	1,292.2	2.8%
For Year: 2013	$172,010	$175,947	$3,937	1,323.3	2.4%

Note:

1. In HECO's scenario without RAM and no sales decoupling, the ROE used is 11.25% for 2010, versus a ROE of 11.00% for the scenario with RAM. This assumption is consistent with the Company's Rebuttal Testimony filed May 22, 2009, in Docket No. 2008-0083.

Decoupling Docket
Hearing Exhibit - Question 1.(b)

PUC-IR-14 Response - Attachment 1 (Amounts in Thousands)	Net Revenues Sheets 1, 5, 9 (Line 4) A	Net Revenues Sheets 2, 6, 10 (Line 2) B	Sales Foregone (B-A) C	RAM Contribution to Revenues Sheets 1, 5, 9 (Line 31) D	RAM/Sales Foregone Ratio (D/C) E	Company's ROE with RAM (Sheets 1, 5, 9, Line 33b) F	Authorized ROE Rate G
Hawaiian Electric Company							
For Year: 2010	$527,404	$529,277	$1,873	$29,453	15.7	9.47%	10.70% 1
For Year: 2011	$559,341	$563,124	$3,783	$26,993	7.1	9.45%	10.70%
For Year: 2012	$588,709	$598,003	$9,294	$10,322	1.1	9.21%	10.70%
For Year: 2013	$589,976	$606,223	$16,247	$37,418	2.3	8.23%	10.70%
Hawaii Electric Light Company							
For Year: 2010	$147,721	$148,427	$706	Test Year	na	5.22%	10.70% 2
For Year: 2011	$171,625	$174,259	$2,634	$5,200	2.0	9.82%	10.70%
For Year: 2012	$171,625	$177,586	$5,961	$8,100	1.4	9.83%	10.70%
For Year: 2013	$182,879	$187,526	$4,647	$3,700	0.8	10.15%	10.70%
Maui Electric Company							
For Year: 2010	$142,760	$142,760	$0	Test Year	na	6.60%	10.70% 3
For Year: 2011	$155,943	$159,902	$3,959	$1,013	0.3	7.96%	10.70%
For Year: 2012	$165,869	$168,121	$2,252	$2,678	1.2	9.59%	10.70%
For Year: 2013	$172,010	$175,947	$3,937	$223	0.1	10.19%	10.70%

Notes:

1. HECO 2007 test year rate case, Interim D&O No. 23749, filed 10/22/2007 in Docket No. 2006-0386.
2. HELCO 2006 test year rate case, Interim D&O No. 23342, filed 4/4/2007 in Docket No. 05-0315.
3. MECO 2007 test year rate case, Interim D&O No. 23926, filed 12/21/2007 in Docket No. 2006-0387.

Decoupling Docket
Hearing Exhibit - Question 1.(c)
Hawaiian Electric Company

2004 Base Revenues:	RBA & RAM A	RBA ONLY B	Recorded Revenues (N.1) C	Sales Foregone (N.2) D=C-B	Impact of RAM (N.5) E=A-B	Sales in gWh F	Illustrative Sales Decoupling Impact on typical residential 600 kWh bill G = D/(F x 1000)*600	Illustrative RAM Impact on typical residential 600 kWh bill H=E/(F x 1000)*600
(Note: Target reset @ Revenue Requirement approved in Rate Case D&O)								
Net Revenues from PUC-IR-14	$355,309	$355,309	$355,309					
Earnings Shortfall + Rev Taxes (N.3)	$38,683	$38,683	$0					
Target Base Revenues -	$393,992	$393,992	$355,309	NA				
2005 Revenues w/RAM & Rev Requirement (Test Year):								
2004 Target Base Revenue (75%)	$295,494	$295,494						
O&M RAM (75%)	$1,892	$0	$0					
Rate Base RAM (75%)	$12,424	$0	$0					
TY Rev Req (25%) - 2005 Final D&O (N.4)	$98,911	$98,911						
2005 Estimated Revenues	$408,721	$394,405	$362,727	-$31,678	$14,315	7721.3	$2.46	$1.11
2006 Revenues w/RAM & Rev Requirement:								
2005 Target Base Revenue	$395,644	$395,644						
O&M RAM (full year)	$4,336	$0						
Rate Base RAM (full year)	$6,309	$0						
2006 Estimated Revenues	$406,289	$395,644	$394,722	-$922	$10,645	7721.3	$0.07	$0.83
2007 Revenues w/RAM & Rev Requirement (Test Year):								
2005 Target Base Revenue (80%)	$325,031	$316,515						
O&M RAM (80%)	$3,125	$0						
Rate Base RAM (80%)	$17,454	$0						
TY Rev Req (20%) - 2007 Interim D&O	$91,732	$91,732						
2007 Estimated Revenues	$437,342	$408,247	$387,229	-$21,018	$20,579	7721.3	$1.63	$1.60
2008 Revenues w/RAM & Rev Requirement:								
2007 Target Base Revenue	$458,659	$458,659						
O&M RAM (full year)	$4,720	$0						
Rate Base RAM (full year)	$3,498	$0						
2008 Estimated Revenues	$466,877	$458,659	$459,102	$443	$8,218	7721.3	-$0.03	$0.64

N.1 See line 4, PUC-IR-14 (filed on 6/29/09)
N.2 Difference between actual revenues and target revenues if only sales decoupling with NO RAM were implemented.
N.3 Revenue adjustment based on line 24, PUC-IR-14 (filed on 6/29/09), grossed-up for revenue taxes to reflect earnings at last authorized ROE.
N.4 Reflects the impact of the Final D&O for the 2005 test year Rate Case, assuming it was issued on the same date as the Interim D&O.
N.5 Impact of RAM during rate case test year is the sum of O&M RAM and Rate Base RAM and does not include the impact of rate increase.

Decoupling Docket
Hearing Exhibit - Question 1.(c)
Hawaii Electric Light Company (HELCO)

2004 Base Revenues:	**RBA & RAM A**	**RBA ONLY B**	**Recorded Revenues (N.1) C**	**Sales Foregone (N.2) D=C-B**	**Impact of RAM (N.4) E=A-B**	**Sales in gWh F**	**Illustrative Sales Decoupling Impact on typical residential 500 kWh bill G = -D/(F x 1000)*500**	**Illustrative RAM Impact on typical residential 500 kWh bill H=E/(F x 1000)*500**
(Note: Target reset @ Revenue Requirement approved in Rate Case D&O)								
Net Revenues from PUC-IR-14	$98,647	$98,647	$98,647					
Earnings Shortfall + Rev Taxes (N.3)	$9,973	$9,973						
Target Base Revenues	$108,620	$108,620	$98,647	NA				
2005 RAM increases:								
2004 Target Base Revenue	$108,620	$108,620						
O&M RAM (full year)	$1,379	$0						
Rate Base RAM (full year)	$18,174	$0						
2005 Estimated Revenues	$128,173	$108,620	$108,685	$65	$19,553	1116.5	-$0.03	$8.76
2006 Revenues w/RAM & Rev Requirement (Test Year):								
2005 Target Base Revenue (1999 Final D&O)	$128,173	$108,620						
O&M RAM (full year)	$2,192	$0						
Rate Base RAM (full year)	$9,644	$0						
2006 Estimated Revenues	$140,009	$108,620	$110,380	$1,760	$11,836	1148.8	-$0.77	$5.15
2007 Revenues w/RAM & Rev Requirement:								
2006 Target Base Revenue (25%)	$35,002	$27,155						
O&M RAM (25%)	$489	$0						
Rate Base RAM (25%)	$2,403	$0						
TY Rev Req (75%) - 2006 Interim D&O	$100,376	$100,376						
2007 Estimated Revenues	$138,270	$127,531	$129,354	$1,823	$2,891	1162.7	-$0.78	$1.24
2008 Revenues w/RAM & Rev Requirement:								
2007 Target Base Revenue	$133,835	$133,835						
O&M RAM (full year)	$1,279	$0						
Rate Base RAM (full year)	-$5,811	$0						
2008 Estimated Revenues	$129,303	$133,835	$130,065	-$3,770	-$4,532	1141.0	$1.65	-$1.99

N.1 See line 4, PUC-IR-14 (filed on 6/29/09)
N.2 Difference between actual revenues and target revenues if only sales decoupling with NO RAM were implemented.
N.3 Revenue adjustment based on line 24, PUC-IR-14 (filed on 6/29/09), grossed-up for revenue taxes to reflect earnings at last authorized ROE.
N.4 Impact of RAM during rate case test year is the sum of O&M RAM and Rate Base RAM and does not include the impact of rate increase.

Decoupling Docket
Hearing Exhibit - Question 1.(c)
Maui Electric Company

2004 Base Revenues:	RBA & RAM A	RBA ONLY B	Recorded Revenues (N.1) C	Sales Foregone (N.2) D=C-B	Impact of RAM (N.4) E=A-B	Sales in gWh F	Illustrative Sales Decoupling Impact on typical residential 500 kWh bill G = D/(F x 1000)*500	Illustrative RAM Impact on typical residential 500 kWh bill H=E/(F x 1000)*500
(Note: Target reset @ Revenue Requirement approved in Rate Case D&O)								
Net Revenues from PUC-IR-14	$115,120	$115,120	$115,120					
Earnings Shortfall + Rev Taxes (N.3)	$0	$0	$0					
Target Base Revenues -	$115,120	$115,120	$115,120	NA				
2005 RAM increases:								
2004 Target Base Revenue	$115,120	$115,120						
O&M RAM (full year)	$636	$0	$0					
Rate Base RAM (full year)	-$892	$0	$0					
2005 Estimated Revenues	$114,864	$115,120	$113,713	-$1,407	-$256	1252.1	$0.56	-$0.10
2006 RAM increases:								
2005 Target Base Revenue	$114,864	$115,120						
O&M RAM (full year)	$815	$0						
Rate Base RAM (full year)	-$1,098	$0						
2006 Estimated Revenues	$114,581	$115,120	$115,412	$292	-$539	1266.5	-$0.12	-$0.21
2007 Revenues w/RAM & Rev Requirement (Test Year):								
2006 Target Base Revenue (97%)	$111,144	$111,666						
O&M RAM (97%)	$1,104	$0						
Rate Base RAM (97%)	$12,515	$0						
TY Rev Req (3%) - 2007 Interim D&O	$4,058	$4,058						
2007 Estimated Revenues	$128,820	$115,724	$119,460	$3,736	$13,619	1280.1	-$1.46	$5.32
2008 Revenues w/RAM & Rev Requirement:								
2007 Target Base Revenue	$135,261	$135,261						
O&M RAM (full year)	$1,400	$0						
Rate Base RAM (full year)	$2,119	$0						
2008 Estimated Revenues	$138,780	$135,261	$128,587	-$6,674	$3,519	1239.2	$2.69	$1.42

N.1 See line 4, PUC-IR-14 (filed on 6/29/09)
N.2 Difference between actual revenues and target revenues if only sales decoupling with NO RAM were implemented.
N.3 Revenue adjustment based on line 24, PUC-IR-14 (filed on 6/29/09), grossed-up for revenue taxes to reflect earnings at last authorized ROE.
N.4 Impact of RAM during rate case test year is the sum of O&M RAM and Rate Base RAM and does not include the impact of rate increase.

ESTIMATE OF NET REVENUE BASED ON AUTHORIZED REVENUE REQUIREMENT

Company	Dkt No	D&O	Date Issued	Type	Test Year	Revenue Req	Fuel	Purch Power	Rev Gross-Up	Net Revenue
HECO	7766	14412	December 11, 1995	Final	1995	**$707,370**	$132,826	$235,072	$35,720	$303,752
	04-0113	22050	September 27, 2005	Interim (N.1)	2005	**$1,274,885**	$449,447	$345,321	$77,166	$402,951
	04-0113	24171	May 1, 2008	Final	2005	**$1,267,578**	$449,447	$345,321	$77,166	$395,644
	06-0386	23749	October 22, 2007	Interim	2007	**$1,480,454**	$543,874	$387,492	$90,429	$458,659
HELCO	99-0207	18365	February 8, 2001	Final	2000	**$180,124**	$17,420	$72,454	$8,726	$81,524
	05-0315	23342	April 4, 2007	Interim	2006	**$348,638**	$195,793	$0	$19,010	$133,835
MECO	97-0346	16922	April 6, 1999	Final	1999	**$148,814**	$41,411	$6,343	$4,637	$96,423
	06-0387	23926	December 21, 2007	Interim	2007	**$370,529**	$180,465	$33,982	$20,821	$135,261

N.1 For purposes of responding to PUC Hrg. Ex. 1, question 1.(c), the Companies have used the estimated net revenue amount based on the revenue requirement authorized in the Commission's Final Decision & Order issued in Docket No. 04-0113 as the sales decoupling, with no adjustment shown for the issuance of the Final Decision & Order.

Hawaiian Electric Company, Limited (HECO)

O&M Forecast Only for Revised PUC-IR-14 - Recast 2004-2008
Rate Case -2007 Test Year - Probable Entitlement
($ Thousands)

	1995 Final Rates	Revenue Requirements to Produce 8.33% 2004 Base Year	2004 Nominal Amount (N.1)	2004 BAU Amount	2004 1 + Index	Notes	2005 BAU * Index Amount	2005 Nominal Amount (N.1)	2005 TOTAL RAM Amount	Notes
Electric Sales Revenue	702,061	838,357					0		840,879	N.6
Other Operating Revenue	2,831	0	0	0	100.0%	N.2	0	0	0	
Gain on Sale of Land	2,478		0	0	100.0%	N.2	0	0	0	
TOTAL OPERATING REVENUES	707,370	838,357	0	0			0		840,879	
Fuel	132,826	103,151	103,151	0	100.0%	N.2	0	103,151	103,151	
Purchased Power	235,072	295,963	295,963	0	100.0%	N.2	0	295,963	295,963	
Production	35,156	0							51,087	
Production Labor *	13,308	21,015		21,015	100.5%	N.3	21,118		21,118	
Production NonLabor *	21,848	29,381	0	29,381	102.0%	N.4	29,969	0	29,969	
Transmission	8,434	0							8,205	
Transmission Labor *	2,878	3,417		3,417	100.5%	N.3	3,434		3,434	
Transmission NonLabor *	5,556	4,678		4,678	102.0%	N.4	4,772		4,772	
Distribution	17,648	0							21,278	
Distribution Labor *	8,150	9,568		9,568	100.5%	N.3	9,615		9,615	
Distribution NonLabor *	9,498	11,434	0	11,434	102.0%	N.4	11,663	0	11,663	
Customer Accounts	7,567	0							10,812	
Customer Accounts Labor *	4,939	6,019		6,019	100.5%	N.3	6,048		6,048	
Customer Accounts NonLabor	2,628	4,670	0	4,670	102.0%	N.4	4,763	0	4,763	
Allowance for Uncoll. Accounts	982	0		0	102.0%	N.4	0		0	
Customer Service	3,292	0							10,996	
Customer Service Labor *	458	2,646		2,646	100.5%	N.3	2,659		2,659	
Customer Service NonLabor	2,834	8,174		8,174	102.0%	N.4	8,337		8,337	
Administration & General	51,838	0							0	
Admin & Gen Labor *	17,529	16,282		16,282	100.5%	N.3	16,362		16,362	
Admin & Gen NonLabor *	34,309	33,705		33,705	102.0%	N.4	34,379		34,379	
Operation and Maintenance	492,815	550,103	399,114	150,989			153,119		552,233	
Depreciation & Amortization	42,425	69,427	na	na			na		69,427	N.7
Amortization of State ITC	0	0		0	100.0%	N.5	0		0	
Taxes Other Than Income	66,628	81,078	na	na			na		81,471	N.8
Interest on Customer Deposits)	102	0		0	100.0%	N.5	0		0	
Income Taxes	31,230	40,817	na	na			na		40,817	
TOTAL OPERATING EXPENSES	633,200	741,425	399,114	150,989			153,119		743,947	
OPERATING INCOME	74,165	96,932	na	na			na		96,932	
							0			
AVERAGE RATE BASE	809,665	1,058,206	na	na			na		1,058,206	
RATE OF RETURN ON AVERAGE RATE BASE	9.16%	9.16%	96,931.7						9.16%	
REVENUE ADJUSTMENT (DIFFERENCE IN TOTAL OPERATING REVENUES)									$2,522	

* Allocated Labor and Nonlabor of total O&M expenses based on 2006 Budget as provided in HELCO-WP-101(A) in the 2006 Rate Case
** Expenses and Rate Base from 2009 Budget (see L. Matsunaga email dated 1/25/09), Electric Sales Revenues Based on Revenue Requirement for
N.1 Based on Rate Case Base Year for fuel & purchased power
N.2 No escalator used.
N.3 Escalation based on collective bargaining agreement of 2005=1.25%, 2006=3.28%, 2007=3.61%, 2008=2.91%, 2009=4.0%

Att. 1 WP-1(c)2 p.1-2 - HECO O&M RAM 2004-5.xls Results-FC

See Labor & Nonlabor Escalators worksheet

N.4 Based on Blue Chip Economic Indicators Consensus, GDP Price Index February issue of RAM year"

N.5 Assumes no change in state ITC amount and no growth based on rate base RAM assumption of no growth in customer deposits

N.6 (Total Operating Expenses less revenue taxes+Operating Income)/(1-PUC & PSC & Franchise Tax rates-Uncoll Factor) less Other Operating re

N.7 Calculated as part of Rate Base RAM, not O&M RAM

N.8 See "Taxes" Tab in Worksheet

Total Base O&M Labor in Test Year

2004	58,947.0	
2005	59,235.8	100.49%
2006	0	0.00%
2007	0	#DIV/0!

Total Base O&M NonLabor in Test Year (excluding Fuel, Purchase Power, & Uncollectibles)

2004	92,042.0	
2005	93,882.8	102.00%
2006	0	0.00%
2007	0	#DIV/0!

Total O&M Labor & NonLabor in Test Year (excluding Fuel, Purchase Power, & Uncollectibles)

2004	150,989.0	
2005	153,118.7	101.41%
2006	0	0.00%
2007	0	#DIV/0!

Total Operating Income

2004	96,931.7	
2005	96,931.7	100.00%
2006	0	0.00%
2007	0	#DIV/0!

Total O&M Expenses & Operating Income (excluding Fuel, Purchase Power, & Uncollectibles)

2004	247,920.7	
2005	250,050.3	100.86%
2006	0	0.00%
2007	0	#DIV/0!

Hawaiian Electric Company, Limited (HECO)

O&M Forecast Only for Revised PUC-IR-14 - Recast 2004-2008
Rate Case -2007 Test Year - Probable Entitlement
($ Thousands)

	2005 Test Year Interim Rates	Notes	2005 Nominal Amount	2005 BAU Amount	2005 1 + Index	Notes	2006 BAU * Index Amount	2006 Nominal Amount	2006 TOTAL RAM Amount	Notes	2006 Nominal Amount	2006 BAU Amount	2006 1 + Index	Notes	2007 BAU * Index Amount	2007 Nominal Amount	2007 TOTAL RAM Amount	Notes
Electric Sales Revenue	1,263,739	N.6							1,268,074	N.6							1,271,980	N.6
Other Operating Revenue	3,478		0	3,478	100.0%	N.2	3,478	0	3,478		0	3,478	100.0%	N.2	3,478	0	3,478	
Gain on Sale of Land	363		0	363	100.0%	N.2	363	0	363		0	363	100.0%	N.2	363	0	363	
TOTAL OPERATING REVENUES	1,267,579		0	3,841			3,841		1,271,915		0	3,841			3,841		1,275,821	
Fuel	449,447		449,447	0	100.0%	N.2	0	449,447	449,447		259,781	189,666	100.0%	N.2	189,666	259,781	449,447	
Purchased Power	345,321		345,321	0	100.0%	N.2	0	345,321	345,321		68,712	276,609	100.0%	N.2	276,609	68,712	345,321	
Production	53,365																	
Production Labor *	24,876		0	24,876	102.5%	N.3	25,503		25,503		0	25,503	102.9%	N.3	26,230		26,230	
Production NonLabor *	28,489		0	28,489	102.5%	N.4	29,201		29,201		0	29,201	102.1%	N.4	29,814		29,814	
Transmission	7,940							0								0		
Transmission Labor *	3,784		0	3,784	102.5%	N.3	3,879		3,879		0	3,879	102.9%	N.3	3,990		3,990	
Transmission NonLabor *	4,156		0	4,156	102.5%	N.4	4,260		4,260		0	4,260	102.1%	N.4	4,349		4,349	
Distribution	19,904																	
Distribution Labor *	9,392		0	9,392	102.5%	N.3	9,629		9,629		0	9,629	102.9%	N.3	9,903		9,903	
Distribution NonLabor *	10,512		0	10,512	102.5%	N.4	10,775		10,775		0	10,775	102.1%	N.4	11,001		11,001	
Customer Accounts	11,232							0								0		
Customer Accounts Labor *	6,140		0	6,140	102.5%	N.3	6,295		6,295		0	6,295	102.9%	N.3	6,474		6,474	
Customer Accounts NonLabor *	5,092		0	5,092	102.5%	N.4	5,219		5,219		0	5,219	102.1%	N.4	5,329		5,329	
Allowance for Uncoll. Accounts	1,195		0	1,195	102.5%	N.4	1,225		1,225		0	1,225	102.1%	N.4	1,251		1,251	
Customer Service	4,262							0								0		
Customer Service Labor *	817		0	817	102.5%	N.3	838		838		0	838	102.9%	N.3	862		862	
Customer Service NonLabor *	3,445		0	3,445	102.5%	N.4	3,531		3,531		0	3,531	102.1%	N.4	3,605		3,605	
Administration & General	54,021		0						0		0						0	
Admin & Gen Labor *	20,512		0	20,512	102.5%	N.3	21,029		21,029		0	21,029	102.9%	N.3	21,628		21,628	
Admin & Gen NonLabor *	33,509		0	33,509	102.5%	N.4	34,347		34,347		0	34,347	102.1%	N.4	35,068	0	35,068	
Operation and Maintenance	946,687		794,768	151,919			155,730	794,768	950,498		328,493	622,005			625,779	328,493	954,272	
Depreciation & Amortization	70,731	N.7	na	na			na		70,731	N.7	na	na			0		70,731	N.7
Amortization of State ITC	0		0	0	100.0%	N.5	0		0		0	0	100.0%	N.5	0		0	
Taxes Other Than Income	118,050	N.6	na	na			na		118,575	N.8	na	na			0		119,085	N.6
Interest on Customer Deposits)	378		0	378	100.0%	N.5	378		378		0	378	100.0%	N.5	0		0	
Income Taxes	39,897		na	na			na		39,897		na	na			0		39,897	
TOTAL OPERATING EXPENSES	1,175,743		794,768	152,297			156,108		1,180,079		328,493	622,383			0		1,183,985	
OPERATING INCOME	91,836			0			0		91,836			0					0 91,836	
AVERAGE RATE BASE	1,060,462		na	na			0		1,060,462		na	na					1,060,462	
RATE OF RETURN ON AVERAGE RATE BASE	8.66%	91,836.0	na	na			na		8.66%	91,836.0	na	na			na		8.66%	91,836.0
REVENUE ADJUSTMENT (DIFFERENCE IN TOTAL OPERATING REVENUES)									$4.336								$3,906	

* Allocated Labor and Nonlabor of total O&M expenses based on 2006 Budget as provided in HELCO-WP-101(A) in the 2006 Rate Case
** Expenses and Rate Base from 2009 Budget (see L. Matsunaga email dated 1/25/09), Electric Sales Revenues Based on Revenue Requirement formula (see N.6)
N.1 Based on Rate Case Base Year for fuel & purchased power
N.2 No escalator used.
N.3 Escalation based on collective bargaining agreement of [illegible]
2009=4.0%
See Labor & Nonlabor Escalators worksheet
N.4 Based on Blue Chip Economic Indicators Consensus, GDP Price Index February issue of RAM year*
N.5 Assumes no change in state ITC amount and no growth based on rate base RAM assumption of no growth in customer deposits
N.6 (Total Operating Expenses less revenue taxes+Operating Income)/(1-PUC & PSC & Franchise Tax rates-Uncoll Factor) less Other Operating revenue & Gain on Sale of Land
N.7 Calculated as part of Rate Base RAM, not O&M RAM
N.8 See "Taxes" Tab in Worksheet

Total Base O&M Labor in Test Year

2004	0		
2005	65,521.7	#DIV/0!	
2006	67,172.8		102.52%
2007	69,087.3		102.85%

Total Base O&M NonLabor in Test Year (excluding Fuel, Purchase Power, & Uncollectibles)

2004	0		
2005	85,202.3	#DIV/0!	
2006	87,332.4		102.50%
2007	1,250.6		1.43%

Total O&M Labor & NonLabor in Test Year (excluding Fuel, Purchase Power, & Uncollectibles)

2004	0		
2005	150,724.0	#DIV/0!	
2006	154,505.2		102.51%
2007	70,337.9		45.52%

Total Operating Income

2004	0		
2005	91,836.0	#DIV/0!	
2006	91,836.0		100.00%
2007			0.00%

Total O&M Expenses & Operating Income (excluding Fuel, Purchase Power, & Uncollectibles)

2004	0		
2005	242,560.0	#DIV/0!	
2006	246,341.2		101.56%
2007	70,337.9		28.55%

Hawaiian Electric Company (HECO)

O&M Forecast Only for Revised PUC-IR-14 - Recast 2004-2008
Rate Case -2007 Test Year - Probable Entitlement
($ Thousands)

	2007 Rate Case Interim Rates	Revenue Requirements to Produce 8.33% 2007 Rate Cas Interim Rates	2007 Nominal Amount (N.1)	2007 BAU Amount	2007 1 + Index	Notes	2008 BAU * Index Amount	2008 Nominal Amount (N.1)	2008 TOTAL RAM Amount	Notes	2008 Nominal Amount	2008 BAU Amount	2008 1 + Index	Notes	2009 BAU * Index Amount	2009 Nominal Amount	2009 TOTAL RAM Amount	Notes	
Electric Sales Revenue	1,475,829	1,475,825					0		1,480,545	N.6							1,486,484	N.6	
Other Operating Revenue	4,125	4,125	0	4,125	100.0%	N.2	4,125	0	4,125		0	4,125	100.0%	N.2	4,125	0	4,125		
Gain on Sale of Land	500	500	0	500	100.0%	N.2	500	0	500		0	500	100.0%	N.2	500	0	500		
TOTAL OPERATING REVENUES	1,480,454	1,480,450	0	4,625			4,625		1,485,170		0	4,625			4,625		1,491,109		
Fuel	543,874	543,874	543,874	0	100.0%	N.2	0	543,874	543,874		543,874	0	100.0%	N.2	0	543,874	543,874		
Purchased Power	387,492	387,492	387,492	0	100.0%	N.2	0	387,492	387,492		387,492	0	100.0%	N.2	0	387,492	387,492		
Production	67,597	67,597																	
Production Labor *	25,588	28,682		28,682	102.2%	N.3	29,299		29,299		0	29,299	103.2%	N.3	30,248		30,248		
Production NonLabor *	42,009	38,915	0	38,915	102.2%	N.4	39,771	0	39,771		0	39,771	101.8%	N.4	40,487	0	40,487		
Transmission	10,272	10,272																	
Transmission Labor *	3,505	4,369		4,369	102.2%	N.3	4,463		4,463		0	4,463	103.2%	N.3	4,608		4,608		
Transmission NonLabor *	6,767	5,903		5,903	102.2%	N.4	6,033		6,033		0	6,033	101.8%	N.4	6,141		6,141		
Distribution	24,663	24,663																	
Distribution Labor *	11,389	10,706		10,706	102.2%	N.3	10,937		10,937		0	10,937	103.2%	N.3	11,291		11,291		
Distribution NonLabor *	13,274	13,957	0	13,957	102.2%	N.4	14,264	0	14,264		0	14,264	101.8%	N.4	14,520	0	14,520		
Customer Accounts	11,720	11,720																	
Customer Accounts Labor *	7,649	5,911		5,911	102.2%	N.3	6,038		6,038		0	6,038	103.2%	N.3	6,234		6,234		
Customer Accounts NonLabor	4,071	5,809	0	5,809	102.2%	N.4	5,937	0	5,937		0	5,937	101.8%	N.4	6,044	0	6,044		
Allowance for Uncoll. Accounts	970	970		970	102.2%	N.4	991		991		0	991	101.8%	N.4	1,009		1,009		
Customer Service	5,890	5,890																	
Customer Service Labor *	820	1,002		1,002	102.2%	N.3	1,024		1,024		0	1,024	103.2%	N.3	1,057		1,057		
Customer Service NonLabor	5,070	4,888		4,888	102.2%	N.4	4,996		4,996		0	4,996	101.8%	N.4	5,085		5,085		
Administration & General	69,517	69,517							0		0						0		
Admin & Gen Labor *	23,508	23,773		23,773	102.2%	N.3	24,284		24,284		0	24,284	103.2%	N.3	25,071		25,071		
Admin & Gen NonLabor *	46,009	45,744		45,744	102.2%	N.4	46,750		46,750		0	46,750	101.8%	N.4	47,592		47,592		
Operation and Maintenance	1,121,995	1,121,995	931,366	190,629			194,786		1,126,152		931,366	194,786			199,387	931,366	1,130,753		
Depreciation & Amortization	78,763	78,763	na	na			na		78,763	N.7	na	na			na		78,763	N.7	
Amortization of State ITC	(1,304)	(1,304)		-1,304	100.0%	N.5	-1,304		-1,304		0	-1,304	100.0%	N.5	-1,304		(726)		
Taxes Other Than Income	137,599	137,551	na	na			na		138,105	N.8	na	na			na		138,840	N.8	
Interest on Customer Deposits)	377	377		377	100.0%	N.5	377		386		0	386	100.0%	N.5	386		411		
Income Taxes	43,177	43,177	na	na			na		43,177		na	na			na		43,177		
TOTAL OPERATING EXPENSES	1,380,607	1,380,559	931,366	189,702			193,859		1,385,279		931,366	193,868			198,469		1,391,218		
												0			0				
OPERATING INCOME	99,847	99,847	na	na			na		99,847		na	na			0		99,847		
							0												
AVERAGE RATE BASE	1,158,316	1,158,316	na	na			na		1,158,316		na	na			na		1,158,316		
RATE OF RETURN ON AVERAGE RATE BASE	8.62%	8.62%	99,891.2						8.62%		99,891.2						8.62%		99,891.2
REVENUE ADJUSTMENT (DIFFERENCE IN TOTAL OPERATING REVENUES)									$4,720								$5,939		

* Allocated Labor and Nonlabor of total O&M expenses based on 2006 Budget as provided in HELCO-WP-101(A) in the 2006 Rate Case
** Expenses and Rate Base from 2009 Budget (see L. Matsunaga email dated 1/25/09), Electric Sales Revenues Based on Revenue Requirement formula (see N.6)
N.1 Based on Rate Case Base Year for fuel & purchased power
N.2 No escalator used.
N.3 Escalation based on collective bargaining agreement of 2005=1.25%, 2006=3.28%, 2007=3.61%, 2008=2.91%, 2009=4.0%
See Labor & Nonlabor Escalators worksheet
N.4 Based on Blue Chip Economic Indicators Consensus, GDP Price Index February issue of RAM year"
N.5 Assumes no change in state ITC amount and no growth based on rate base RAM assumption of no growth in customer deposits
N.6 (Total Operating Expenses less revenue taxes+Operating Income)/(1-PUC & PSC & Franchise Tax rates-Uncoll Factor) less Other Operating revenue & Gain on Sale of Land
N.7 Calculated as part of Rate Base RAM, not O&M RAM
N.8 See "Taxes" Tab in Worksheet

ATTACHMENT 1
WP-1(c)2
PAGE 5 OF 7

Total Base O&M Labor in Test Year

2007	74,443.2	
2008	76,043.7	102.15%
2009	78,507.5	103.24%

Total Base O&M NonLabor in Test Year (excluding Fuel, Purchase Power, & Uncollectibles)

2007	115,215.8	
2008	117,750.6	102.20%
2009	119,870.1	101.80%

Total O&M Labor & NonLabor in Test Year (excluding Fuel, Purchase Power, & Uncollectibles)

2007	189,659.0	
2008	193,794.3	102.18%
2009	198,377.6	102.37%

Total Operating Income

2007	99,846.8	
2008	99,846.8	100.00%
2009	99,846.8	100.00%

Total O&M Expenses & Operating Income (excluding Fuel, Purchase Power, & Uncollectibles)

2007	289,505.8	
2008	293,641.1	101.43%
2009	298,224.4	101.56%

Hawaiian Electric Company, Inc.
Decoupling-Rate Base RAM Illustration, 2004-2008
(RATE BASE CHANGE)
($000s)

			2004 RAM			2005 RAM			2006 RAM			2007 RAM			2008 RAM		
		Actual 12/31/2002 (as needed)	HECO Rate Base -- Average Actual 12/31/03	2004 Changes	RAM Est 12/31/04	Actual 12/31/04	2005 Changes	RAM Est 12/31/05	Actual 12/31/05	2006 Changes	RAM Est 12/31/06	Actual 12/31/06	2007 Changes	RAM Est 12/31/07	Actual 12/31/07	2008 Changes	RAM Est 12/31/08
1	**Net Plant In Service**																
2	Plant in Service:																
3	Starting Balance -Gen'l Accounting / Budget				$ 2,108,795	$ 2,108,795		$ 2,229,969	$ 2,229,969		$ 2,329,243	$ 2,329,243		$ 2,453,556	2,453,556		2,543,832
4						-			-			-			-		
5	Additions, net			$ 75,524	75,524	121,174	$ 105,742	105,742	99,274	$ 108,105	108,105	124,313	$ 90,276	90,276	76,073	$ 120,234	120,234
6	Retirements					-			-			-			-		
7	Ending Balance	2,047,717	2,108,795	75,524	2,184,319	2,229,969	105,742	2,335,711	2,329,243	108,105	2,437,348	2,453,556	90,276	2,543,832	2,529,629	120,234	2,664,066
8	Accumulated Depreciation:																
9	Starting Balance - Gen'l Accounting				(932,809)	(932,809)		(980,946)	(980,946)		(1,045,596)	(1,045,596)		(1,116,291)	(1,116,291)		(1,168,053)
10	Cost of Removal				-			-			-			-			-
11	Salvage				-			-			-			-			-
12	Depreciation Accrual	(70,587)	(74,045)	(78,236)	(78,236)	(76,753)	(83,178)	(83,178)	(78,170)	(87,347)	(87,347)	(82,854)	(90,046)	(90,046)	(87,460)	(92,837)	(92,837)
13	Retirements			-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Ending Balance (1)	(872,332)	(932,809)	(78,236)	(1,011,045)	(980,946)	(83,178)	(1,064,123)	(1,045,596)	(87,347)	(1,132,943)	(1,116,291)	(90,046)	(1,206,336)	(1,168,053)	(92,837)	(1,260,890)
15	Net Plant in Service	1,175,385	1,175,986	(2,712)	1,173,274	1,249,023	22,564	1,271,588	1,283,647	20,758	1,304,405	1,337,265	230	1,337,496	1,361,576	27,397	1,403,176
16	**Deductions**																
17	Unamortized CIAC - Gen'l Accounting		(143,814)	(9,381)	(145,908)	(144,322)	(11,678)	(148,516)	(156,287)	(23,332)	(171,563)	(164,092)	(10,190)	(165,794)	(176,425)	(12,093)	(179,509)
17a	Adjustment for CIAC amortization			7,287			7,484			8,056			8,488			9,009	
17b	Adjustment for CIAC amortization - incremental portion (2)																
18	Accumulated Def Income Taxes-Gen'l Acc		(137,919)	(9,484)	(147,403)	(146,812)	(8,974)	(155,786)	(160,351)	(6,883)	(167,234)	(92,805)	(7,848)	(100,653)	(130,573)	(2,151)	(132,724)
19	*Total*		(281,733)	(11,578)	(293,311)	(291,134)	(13,168)	(304,302)	(316,638)	(22,159)	(338,797)	(256,897)	(9,550)	(266,447)	(306,998)	(5,235)	(312,233)
20	Net Rate Base (before working ca:	$ 1,175,385	$ 894,253	$ (14,290)	879,963	$ 957,889	$ 9,396	967,285	$ 967,009	$ (1,401)	965,609	$ 1,080,368	$ (9,320)	1,071,049	$ 1,054,579	22,162	$ 1,090,943
21	Average Rate Base	$ 1,034,819			$ 887,108			$ 962,587			$ 966,309			$ 1,075,708			$ 1,072,761
22	Average Change in Rate Base:		CHANGE IN 2004 RATE BASE			CHANGE IN 2005 RATE BASE			CHANGE IN 2006 RATE BASE			CHANGE IN 2007 RATE BASE			CHANGE IN 2008 RATE BASE		
23	Baseline Additions		$ 72,341			$ 83,920			$ 83,445			$ 86,191			$ 87,727		
24	Major CIP Project Additions (3)		3,183			21,822			24,660			4,085			32,507		
25	Accumulated Depreciation		(78,236)			(83,178)			(87,347)			(90,046)			(92,837)		
26	Net Plant																
27	ADIT - Baseline		(7,201)			(6,659)			(8,818)			(6,432)			(2,334)		
28	ADIT - Major CIP		(284)			(845)			(1,134)			(148)			(222)		
29	ADIT (CIAC) - Baseline		(1,999)			(1,470)			(938)			(1,268)			(38)		
30	ADIT (CIAC) - Major CIP		-			-			4,007			-			443		
31	CIAC - Baseline		(9,381)			(9,216)			(10,826)			(10,190)			(10,911)		
32	CIAC - Major CIP		-			(2,462)			(12,506)			-			(1,182)		
33	Total Change in Rate Base				Change In Revenue Requirement	$ (20,652)		Change In Revenue Requirement	$ (30,215)		Change In Revenue Requirement	$ (18,038)		Change In Revenue Requirement	$ (14,244)		Change In Revenue Requirement
34	Effective Pre-Tax Return	13.95%		13.95%			13.95%			13.68%			13.68%			13.58%	
35	Gross Return on Rate Base	$ 144,357		$ 123,752	$ (20,606)		$ 134,281	$ 10,529		$ 132,191	$ (2,090)		$ 147,157	$ 14,966		$ 145,681	$ (1,476)
36	Income Statement Effects:																
37	Less: CIAC Amortization				(313)			(389)			(778)			(340)			(403)
38	Add: Annualized Prior Year Depreciation				4,191			6,425			9,177			7,192			5,377
39	Revenue Requirement on Plant Additions				$ (16,727)			$ 16,565			$ 6,309			$ 21,818			$ 3,498

(1) Actual cost of removal, salvage and retirements are included in actual ending Accumulated Depreciation balance but are not shown separately above.
(2) For the purposes of estimating the rate base RAM for 2004-2008, Line 17b was not included as Line 17a represent the actual amortization amounts for each year based on beginning of year balances.
(3) Major projects ($2.5 million-+) included in the rate base RAM calculation for 2004-2008 are provided below. Other major projects were completed during this period but were not included in the rate base RAM calculation as they were not completed in January - September of the RAM year (see below). In order to respond in a timely manner, used available project cost information which is based on the final report filed with the Commission, instead of the PUC-authorized cost information as proposed in this proceeding, for estimating the 2004-2008 rate base RAMs.

Major projects included in the rate base RAM calculation:

Project Description	Docket No.	In-service date	Cost
Kahe 5 boiler control upgrade	01-0272	May-04	$3,182,632
Mokuone substation	02-0142	Mar-05	$6,862,703
Salt Lake Boulevard widening	01-0189	Mar-05	$4,873,891
New Kuahua substation	03-0260	Sep-05	$10,085,690
Ford Island substation	04-0278	Mar-06	$24,659,976
Kahe 3 boiler controls upgrade	02-0206	Sep-07	$4,085,000
Ko Olina substation	05-0056	Jan-08	$5,006,729
New dispatch center	03-0360	Feb-08	$27,499,925

Projects not included in the rate base RAM calculation:

Project Description	Docket No.	In-service date	Cost
Waiau fuel oil pipeline	01-0444	Dec-04	$40,622,469
Ward air conditioning improvement	00-0040	Nov-05	$8,342,000
Telecommunications system	03-0124	Dec-05	$4,642,489
Kahe 4 boiler controls upgrade	04-0051	Nov-06	$4,693,095
Mamala subdivision	04-0350	Oct-07	$7,441,724
Ocean Pointe substation	05-0217	Nov-07	$3,657,666

Hawaii Electric Light Company, Inc. (HELCO)

O&M Forecast Only for Revised PUC-IR-14 - Recast 2004 - 2008
Rate Case - 2000 Test Year - Settlement Results of Operations
($ Thousands)

	2000 Rate Case Final Rates	Revenue Requirements to Produce 9.14% 2004 Final Rates	2004 Nominal Amount (N.1)	2004 BAU Amount	2004 1 + Index	Notes	2005 BAU * Index Amount	2005 Nominal Amount (N.1)	2005 TOTAL RAM Amount	Notes	2005 Nominal Amount	2005 BAU Amount	2005 1 + Index	Notes	2006 BAU * Index Amount	2006 Nominal Amount	2006 TOTAL RAM Amount	Notes
Electric Sales Revenue	179,261	147,955					0		149,334	N.6							151,526	N.6
Other Operating Revenue	864	864	0	864	100.0%	N.2	864	0	864		0	864	100.0%	N.2	864	0	864	
Gain on Sale of Land			0	0	100.0%	N.2	0	0	0		0	0	100.0%	N.2	0	0	0	
TOTAL OPERATING REVENUES	180,125	148,819	0	864			864		150,198		0	864			864		152,390	
Fuel	17,420		0	0		N.2	0	0	0		0	0	100.0%	N.2	0	0	0	
Purchased Power	72,454		0	0		N.2	0	0	0		0	0	100.0%	N.2	0	0	0	
Production	8,373																	
Production Labor *	6,077			0		N.3	0		0		0	0	102.2%	N.3	0		0	
Production NonLabor *	2,296		0	0		N.4	0	0	0		0	0	102.2%	N.4	0	0	0	
Transmission	1,439																	
Transmission Labor *	753			0		N.3	0		0		0	0	102.2%	N.3	0		0	
Transmission NonLabor *	686			0		N.4	0		0		0	0	102.2%	N.4	0		0	
Distribution	4,410																	
Distribution Labor *	1,783			0		N.3	0		0		0	0	102.2%	N.3	0		0	
Distribution NonLabor *	2,627		0	0		N.4	0	0	0		0	0	102.2%	N.4	0	0	0	
Customer Accounts	2,555																	
Customer Accounts Labor *	1,544			0		N.3	0		0		0	0	102.2%	N.3	0		0	
Customer Accounts NonLabor *	1,011		0	0		N.4	0	0	0		0	0	102.2%	N.4	0	0	0	
Allowance for Uncoll. Accounts	308			0		N.4	0		0		0	0	102.2%	N.4	0		0	
Customer Service Adjusted for DSM	1,366																	
Customer Service Labor *	438			0		N.3	0		0		0	0	102.2%	N.3	0		0	
Customer Service NonLabor *	928			0		N.4	0		0		0	0	102.2%	N.4	0		0	
Administration & General (excludin	5,657	77,318							0		0						0	
Admin & Gen Labor *	2,116	14,214		14,214	100.5%	N.3	14,284		14,284		0	14,284	102.5%	N.3	14,644		14,644	
Admin & Gen NonLabor *	3,541	63,104		63,104	102.0%	N.4	64,366		64,366		0	64,366	102.5%	N.4	65,975		65,975	
Operation and Maintenance	113,982	77,318	0	77,318			78,650		78,650		0	78,650			80,619	0	80,619	
Depreciation & Amortization	18,454	21,163	na	na			na		21,163	N.7	na	na			na		21,163	N.7
Amortization of State ITC	0	0		0	100.0%	N.5	0		0		0	0	100.0%	N.5	0		0	
Taxes Other Than Income	17,196	17,044	na	na			na		14,467	N.8	na	na			na		14,690	N.8
Interest on Customer Deposits (N.1	42	42		42	100.0%	N.5	42		42		0	42	100.0%	N.5	42		42	
Income Taxes	7,636	8,996	na	na			na		8,996		na	na			na		8,996	
TOTAL OPERATING EXPENSES	157,310	124,563	0	77,360			78,692		123,318		0	78,692			80,661		125,510	
												0			0		0	
OPERATING INCOME	22,815	26,880	na	na			na		26,880		na	na			0		26,880	
							0											
AVERAGE RATE BASE	249,617	294,091	na	na			na		294,091		na	na			na		294,091	
RATE OF RETURN ON AVERAGE RATE BASE	9.14%	9.14%	24,255.5						9.14%								9.14%	
REVENUE ADJUSTMENT (DIFFERENCE IN TOTAL OPERATING REVENUES)									$1,379								$2,192	

* Allocated Labor and Nonlabor of total O&M expenses based on Annotated spreadsheet for year 2000
** Expenses and Rate Base from PUC-IR-14-Income Taxes-Other Taxes (Note for test year 2000, property taxes of $152K included into rev req formula)
N.1 See "Nominal" Tab in Worksheet
N.2 No escalator used.
N.3 Escalation based on collective bargaining agreement of 2005=1.25%, 2006=3.28%, 2007=3.61%, 2008=2.91%, 2009=4.0%
See Labor & Nonlabor Escalators worksheet
N.4 Based on Blue Chip Economic Indicators Consensus, GDP Price Index February issue of RAM year"
N.5 Assumes no change in state ITC amount and no growth based on rate base RAM assumption of no growth in customer deposits
N.6 (Total Operating Expenses less revenue taxes+Operating Income)/(1-PUC & PSC & Franchise Tax rates-Uncoll Factor) less Other Operating revenue & Gain on Sale of Land
N.7 Calculated as part of Rate Base RAM, not O&M RAM
N.8 See "Taxes" Tab in Worksheet
N.9 No change to rate base from 2009 so only O&M expense impacts calculated.

Total Base O&M Labor in Test Year			
	2010	14,214.0	
	2011	14,283.6	100.49%
	2012	14,643.6	102.52%
	2013	#REF!	#REF!
Total Base O&M NonLabor in Test Year (excluding Fuel, Purchase Power, & Uncollectibles)			
	2010	63,104.0	
	2011	64,366.1	102.00%
	2012	65,975.2	102.50%
	2013	#REF!	#REF!
Total O&M Labor & NonLabor in Test Year (excluding Fuel, Purchase Power, & Uncollectibles)			
	2010	77,318.0	
	2011	78,649.7	101.72%
	2012	80,618.8	102.50%
	2013	#REF!	#REF!
Total Operating Income			
	2010	26,879.9	
	2011	26,879.9	100.00%
	2012	26,879.9	100.00%
	2013	#REF!	#REF!
Total O&M Expenses & Operating Income (excluding Fuel, Purchase Power, & Uncollectibles)			
	2010	104,197.9	
	2011	105,529.6	101.28%
	2012	107,498.7	101.87%
	2013	#REF!	#REF!

Hawaii Electric Light Company, Inc. (HELCO)

O&M Forecast Only for Revised PUC-IR-14 - Recast 2004 - 2008
Rate Case - 2000 Test Year - Settlement Results of Operations
($ Thousands)

	2006 Rate Case Interim Rates	Revenue Requirements to Produce 8.33% 06 Rate Ca Interim Rates	2006 Nominal Amount (N.1)	2006 BAU Amount	2006 1 + Index	Notes
Electric Sales Revenue	347,561	347,561				
Other Operating Revenue	1,097	1,097	0	1,097	100.0%	N.2
Gain on Sale of Land			0	0	100.0%	N.2
TOTAL OPERATING REVENUES	348,638	348,638	0	1,097		
Fuel	78,584	78,584	78,584	0	100.0%	N.2
Purchased Power	117,210	117,210	117,210	0	100.0%	N.2
Production	21,041	21,041				
Production Labor *	8,382	8,382		8,382	102.9%	N.3
Production NonLabor *	12,659	12,659	0	12,659	102.1%	N.4
Transmission	2,341	2,341				
Transmission Labor *	909	909		909	102.9%	N.3
Transmission NonLabor *	1,432	1,432		1,422	102.1%	N.4
Distribution	6,364	6,364				
Distribution Labor *	2,430	2,430		2,430	102.9%	N.3
Distribution NonLabor *	3,934	3,934	0	3,934	102.1%	N.4
Customer Accounts	3,186	3,186				
Customer Accounts Labor *	1,752	1,752		1,752	102.9%	N.3
Customer Accounts NonLabor *	1,433	1,433	0	1,433	102.1%	N.4
Allowance for Uncoll. Accounts	417	417		417	102.1%	N.4
Customer Service Adjusted for DSM	1,509	1,509				
Customer Service Labor *	405	405		405	102.9%	N.3
Customer Service NonLabor *	1,104	1,104		1,104	102.1%	N.4
Administration & General (excludin	15,214	15,214				
Admin & Gen Labor *	5,305	5,305		5,305	102.9%	N.3
Admin & Gen NonLabor *	9,909	9,909		9,909	102.1%	N.4
Operation and Maintenance	245,864	245,864	195,793	50,071		
Depreciation & Amortization	28,772	28,772	na	na		
Amortization of State ITC	(490)	(490)		-490	100.0%	N.5
Taxes Other Than Income	32,354	32,354	na	na		
Interest on Customer Deposits (N.1	56	56		56	100.0%	N.5
Income Taxes	12,324	12,324	na	na		
TOTAL OPERATING EXPENSES	318,880	318,880	195,793	49,636		
OPERATING INCOME	29,758	29,758	na	na		
AVERAGE RATE BASE	357,238	357,238	na	na		
RATE OF RETURN ON AVERAGE RATE BASE	8.33%	8.33%				
REVENUE ADJUSTMENT (DIFFERENCE IN TOTAL OPERATING REVENUES)			29,757.7			

	2007 BAU * Index Amount	2007 Nominal Amount (N.1)	2007 TOTAL RAM Amount	Notes	2007 Nominal Amount	2007 BAU Amount	2007 1 + Index	Notes
Electric Sales Revenue	0		349,495	N.6				
Other Operating Revenue	1,097	0	1,097		0	1,097	100.0%	N.2
Gain on Sale of Land	0	0	0		0	0	100.0%	N.2
TOTAL OPERATING REVENUES	1,097		350,591		0	1,097		
Fuel	0	78,584	78,584		78,584	0	100.0%	N.2
Purchased Power	0	117,210	117,210		117,210	0	100.0%	N.2
Production								
Production Labor *	8,621		8,621		0	8,621	102.2%	N.3
Production NonLabor *	12,925	0	12,925		0	12,925	102.2%	N.4
Transmission								
Transmission Labor *	935		935		0	935	102.2%	N.3
Transmission NonLabor *	1,462		1,462		0	1,462	102.2%	N.4
Distribution								
Distribution Labor *	2,500		2,500		0	2,500	102.2%	N.3
Distribution NonLabor *	4,016	0	4,016		0	4,016	102.2%	N.4
Customer Accounts								
Customer Accounts Labor *	1,802		1,802		0	1,802	102.2%	N.3
Customer Accounts NonLabor *	1,464	0	1,464		0	1,464	102.2%	N.4
Allowance for Uncoll. Accounts	426		426		0	426	102.2%	N.4
Customer Service Adjusted for DSM								
Customer Service Labor *	416		416		0	416	102.2%	N.3
Customer Service NonLabor *	1,127		1,127		0	1,127	102.2%	N.4
Administration & General (excludin			0		0			
Admin & Gen Labor *	5,456		5,456		0	5,456	102.2%	N.3
Admin & Gen NonLabor *	10,117		10,117		0	10,117	102.2%	N.4
Operation and Maintenance	51,266		247,059		195,793	51,266		
Depreciation & Amortization	na		28,772	N.7	na	na		
Amortization of State ITC	-490		-490		0	-490	100.0%	N.5
Taxes Other Than Income	na		33,072	N.8	na	na		
Interest on Customer Deposits (N.1	56		96		0	96	100.0%	N.5
Income Taxes	na		12,324		na	na		
TOTAL OPERATING EXPENSES	50,832		320,834		195,793	50,672		
OPERATING INCOME	na		29,758			0		
AVERAGE RATE BASE	0		357,238		na	na		
RATE OF RETURN ON AVERAGE RATE BASE	na		8.33%		na	na		
REVENUE ADJUSTMENT (DIFFERENCE IN TOTAL OPERATING REVENUES)			$1,954					

	2008 BAU * Index Amount	2008 Nominal Amount	2008 TOTAL RAM Amount	Notes	2008 Nominal Amount	2008 BAU Amount	2008 1 + Index	Notes
Electric Sales Revenue			350,774	N.6				
Other Operating Revenue	1,097	0	1,097		0	1,097	100.0%	N.2
Gain on Sale of Land	0	0	0		0	0	100.0%	N.2
TOTAL OPERATING REVENUES	1,097		351,870		0	1,097		
Fuel	0	78,584	78,584		78,584	0	100.0%	N.2
Purchased Power	0	117,210	117,210		117,210	0	100.0%	N.2
Production								
Production Labor *	8,806		8,806		0	8,806	103.2%	N.3
Production NonLabor *	13,209	0	13,209		0	13,209	101.8%	N.4
Transmission								
Transmission Labor *	955		955		0	955	103.2%	N.3
Transmission NonLabor *	1,494		1,494		0	1,494	101.8%	N.4
Distribution								
Distribution Labor *	2,553		2,553		0	2,553	103.2%	N.3
Distribution NonLabor *	4,105	0	4,105		0	4,105	101.8%	N.4
Customer Accounts								
Customer Accounts Labor *	1,841		1,841		0	1,841	103.2%	N.3
Customer Accounts NonLabor *	1,496	0	1,496		0	1,496	101.8%	N.4
Allowance for Uncoll. Accounts	435		435		0	435	101.8%	N.4
Customer Service Adjusted for DSM								
Customer Service Labor *	425		425		0	425	103.2%	N.3
Customer Service NonLabor *	1,152		1,252		0	1,152	101.8%	N.4
Administration & General (excludin			0		0			
Admin & Gen Labor *	5,576		5,576		0	5,576	103.2%	N.3
Admin & Gen NonLabor *	10,339		10,339		0	10,339	101.8%	N.4
Operation and Maintenance	52,387	195,793	248,180		195,793	52,387		
Depreciation & Amortization	na		28,772	N.7				
Amortization of State ITC	-490		-490					
Taxes Other Than Income	na		33,228	N.8				
Interest on Customer Deposits (N.1	96		99					
Income Taxes	na		12,324					
TOTAL OPERATING EXPENSES	51,993		322,113		195,793	52,387		
OPERATING INCOME	0		0 29,758			0		
AVERAGE RATE BASE	0		357,238		na	na		
RATE OF RETURN ON AVERAGE RATE BASE	na		8.33%		na	na		
REVENUE ADJUSTMENT (DIFFERENCE IN TOTAL OPERATING REVENUES)			$1,279					

	2009 BAU * Index Amount	2009 Nominal Amount	2009 TOTAL RAM Amount	Notes
Electric Sales Revenue			352,138	N.6
Other Operating Revenue	1,097	0	1,097	
Gain on Sale of Land	0	0	0	
TOTAL OPERATING REVENUES	1,097		353,294	
Fuel	0	78,584	78,584	N.2
Purchased Power	0	117,210	117,210	N.2
Production				
Production Labor *	9,092		9,092	N.3
Production NonLabor *	13,447	0	13,447	N.4
Transmission				
Transmission Labor *	986		986	N.3
Transmission NonLabor *	1,521		1,521	N.4
Distribution				
Distribution Labor *	2,636		2,636	N.3
Distribution NonLabor *	4,179	0	4,179	N.4
Customer Accounts				
Customer Accounts Labor *	1,900		1,900	N.3
Customer Accounts NonLabor *	1,523	0	1,523	N.4
Allowance for Uncoll. Accounts	443		443	N.4
Customer Service Adjusted for DSM				
Customer Service Labor *	439		439	N.3
Customer Service NonLabor *	1,173		1,173	N.4
Administration & General (excludin			0	
Admin & Gen Labor *	5,757		5,757	N.3
Admin & Gen NonLabor *	10,525		10,525	N.4
Operation and Maintenance	53,620	195,793	249,413	
Depreciation & Amortization			28,772	
Amortization of State ITC			-490	N.5
Taxes Other Than Income			33,416	
Interest on Customer Deposits (N.1			99	N.5
Income Taxes			12,324	
TOTAL OPERATING EXPENSES	53,620		323,536	
OPERATING INCOME	0		29,758	
AVERAGE RATE BASE	0		357,238	
RATE OF RETURN ON AVERAGE RATE BASE	na		8.33%	
REVENUE ADJUSTMENT (DIFFERENCE IN TOTAL OPERATING REVENUES)			$1,424	

* Allocated Labor and NonLabor of total O&M expenses based on 2006 Budget as provided in HELCO-WP-101(A) in the 2006 Rate Case
** Expenses and Rate Base from 2009 Budget

N.1 Based on Rate Case Base Year for fuel & purchased power
N.2 No escalator used.
N.3 Escalation based on collective bargaining agreement of 2005=1.25%, 2006=3.28%, 2007=3.61%, 2008=2.91%, 2009=4.0%
See Labor & Nonlabor Escalators worksheet
N.4 Based on Blue Chip Economic Indicators Consensus, GDP Price Index February issue of RAM year"
N.5 Assumes no change in state ITC amount and no growth based on rate base RAM assumption of no growth in customer deposits
N.6 (Total Operating Expenses less revenue taxes+Operating Income)/(1-PUC & PSC & Franchise Tax rates-Uncoll Factor) less Other Operating revenue & Gain on Sale of Land
N.7 Calculated as part of Rate Base RAM, not O&M RAM
N.8 See "Taxes" Tab in Worksheet
N.9 No change to rate base from 2009 so only O&M expense impacts calculated.

Total Base O&M Labor in Test Year		
2010	19,183.5	
2011	19,730.2	102.85%
2012	20,157.2	102.16%
2013	20,810.3	103.24%
Total Base O&M NonLabor in Test Year (excluding Fuel, Purchase Power, & Uncollectibles)		
2010	30,470.3	
2011	31,110.2	102.10%
2012	31,794.6	102.20%
2013	32,366.9	101.80%
Total O&M Labor & NonLabor in Test Year (excluding Fuel, Purchase Power, & Uncollectibles)		
2010	49,653.8	
2011	50,840.4	102.39%
2012	51,951.8	102.19%
2013	53,177.2	102.36%
Total Operating Income		
2010	29,757.7	
2011	29,757.7	100.00%
2012	29,757.7	100.00%
2013	29,757.9	100.00%
Total O&M Expenses & Operating Income (excluding Fuel, Purchase Power, & Uncollectibles)		
2010	79,411.5	
2011	80,598.1	101.49%
2012	81,709.5	101.38%
2013	82,935.1	101.50%

Hawaii Electric Light Company, Inc.
Decoupling-Rate Base RAM Illustration, 2004-2008
(RATE BASE CHANGE)
($000s)

			2004 RAM			2005 RAM			2006 RAM			2007 RAM			2008 RAM		
			HELCO Rate Base -- Average														
		Actual 12/31/2002 (as needed)	Actual 12/31/03	2004 Changes	RAM Est 12/31/04	Actual 12/31/04	2005 Changes	RAM Est 12/31/05	Actual 12/31/05	2006 Changes	RAM Est 12/31/06	Actual 12/31/06	2007 Changes	RAM Est 12/31/07	Actual 12/31/07	2008 Changes	RAM Est 12/31/08
1	**Net Plant In Service**																
2	Plant in Service:																
3	Starting Balance -Gen'l Accounting / Budget		$ 572,183		$ 592,183	$ 592,183		$ 717,141	$ 717,141		$ 769,539	$ 769,539		$ 812,322	$ 812,322		847,048
4						-			-			-			-		
5	Additions, net		20,000	$ 124,159	124,159	124,958	$ 21,920	21,920	52,398	$ 24,180	24,180	42,783	$ 34,726	34,726	22,768	$ 38,378	38,378
6	Retirements					-			-			-			-		
7	Ending Balance	572,183	592,183	124,159	716,342	717,141	21,920	739,061	769,539	24,180	793,719	812,322	34,726	847,048	835,090	38,378	885,426
8	Accumulated Depreciation:																
9	Starting Balance - Gen'l Accounting				(238,320)	(238,320)		(253,294)	(253,294)		(275,444)	(275,444)		(298,590)	(298,590)		(324,517)
10	Cost of Removal				-			-			-			-			-
11	Salvage				-			-			-			-			-
12	Depreciation Accrual	(22,996)	(20,293)	(24,818)	(24,818)	(21,163)	(30,084)	(30,084)	(27,177)	(32,975)	(32,975)	(29,722)	(34,816)	(34,816)	(30,094)	(35,792)	(35,792)
13	Retirements			-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Ending Balance (1)	(256,469)	(238,320)	(24,818)	(263,138)	(253,294)	(30,084)	(283,378)	(275,444)	(32,975)	(308,419)	(298,590)	(34,816)	(333,406)	(324,517)	(35,792)	(360,309)
15	Net Plant in Service	315,714	353,863	99,341	453,204	463,847	(8,164)	455,683	494,095	(8,795)	485,300	513,732	(90)	513,642	510,573	2,586	525,117
16	**Deductions**																
17	Unamortized CIAC - Gen'l Accounting		(56,275)	(4,478)	(57,723)	(56,042)	(3,717)	(56,739)	(56,555)	(3,488)	(57,366)	(59,936)	(4,187)	(60,892)	(63,002)	(4,708)	(64,282)
17a	Adjustment for CIAC amortization			3,030			3,020			2,677			3,231			3,428	
17b	Adjustment for CIAC amortization - incremental portion (2)																
18	Accumulated Def Income Taxes-Gen'l Acc		(24,022)	(13,951)	(37,973)	(23,590)	5,275	(18,315)	(25,147)	6,189	(18,958)	(13,241)	7,734	(5,507)	(17,791)	5,652	(12,139)
19	Total		(80,297)	(15,399)	(95,696)	(79,632)	4,578	(75,054)	(81,702)	5,378	(76,324)	(73,177)	6,778	(66,399)	(80,793)	4,372	(76,421)
20	Net Rate Base (before working cash) $	315,714	$ 273,566	$ 83,942	357,508	$ 384,215	$ (3,586)	380,629	$ 412,393	$ (3,417)	408,976	$ 440,555	$ 6,688	447,243	$ 429,780	6,958	$ 448,696
21	Average Rate Base	$ 294,640			$ 315,537			$ 382,422			$ 410,685			$ 443,899			$ 439,238
22	Average Change in Rate Base:		CHANGE IN 2004 RATE BASE			CHANGE IN 2005 RATE BASE			CHANGE IN 2006 RATE BASE			CHANGE IN 2007 RATE BASE			CHANGE IN 2008 RATE BASE		
23	Baseline Additions		$ 19,447			$ 18,884			$ 24,180			$ 34,726			$ 38,378		
24	Major CIP Project Additions (3)		104,712			3,036			-			-			-		
25	Accumulated Depreciation		(24,818)			(30,084)			(32,975)			(34,816)			(35,792)		
26	Net Plant																
27	ADIT - Baseline		2,489			5,437			5,750			7,797			6,375		
28	ADIT - Major CIP		(17,198)			(735)			-			-			-		
29	ADIT (CIAC) - Baseline		758			573			439			(63)			(723)		
30	ADIT (CIAC) - Major CIP		-			-			-			-			-		
31	CIAC - Baseline		(4,478)			(3,717)			(3,488)			(4,187)			(4,708)		
32	CIAC - Major CIP		-			-			-			-			-		
33	Total Change in Rate Base				Change In Revenue Requirement	$ 1,558		Change In Revenue Requirement	$ 2,701		Change In Revenue Requirement	$ 3,547		Change In Revenue Requirement	$ 944		Change In Revenue Requirement
34	Effective Pre-Tax Return	14.02%		14.02%			14.02%			14.02%			14.02%			12.97%	
35	Gross Return on Rate Base	$ 41,309		$ 44,238	$ 2,930		$ 53,616	$ 9,377		$ 57,578	$ 3,962		$ 62,235	$ 4,657		$ 56,969	$ (5,265)
36	Income Statement Effects:																
37	Less: CIAC Amortization				(149)			(124)			(116)			(140)			(157)
38	Add: Annualized Prior Year Depreciation				4,525			8,921			5,798			5,094			5,698
39	Revenue Requirement on Plant Additions				$ 7,306			$ 18,174			$ 9,644			$ 9,611			$ 276

(1) Actual cost of removal, salvage and retirements are included in actual ending Accumulated Depreciation balance but are not shown separately above.
(2) For the purposes of estimating the rate base RAM for 2004-2008, Line 17b was not included as Line 17a represent the actual amortization amounts for each year based on beginning of year balances.
(3) Two major projects ($2.5 million-+) were included in the rate base RAM calculation for 2004-2008 as they were completed in January - September of the RAM year – the Keahole CT-4/CT-5 projects with an in-service date of May 2004 (Total cost $104,712,000; Dkts. No. 7048/7623) and the Keahole CT-2 noise mitigation project in September 2005 (Total cost $3,036,195; Dkt. No. 04-0352). In order to respond in a timely manner, used available project cost information which is based on the final report filed with the Commission, instead of the PUC-authorized cost information as proposed in this proceeding, for calculating the 2004-2008 rate base RAMs.

ATTACHMENT 1
WP-1(c)4
PAGE 1 OF 5

Maui Electric Company, Limited (MECO)

O&M Forecast Only for Revised PUC-IR-14 - Recast 2004-2008
Rate Case -2007 Test Year - Probable Entitlement
($ Thousands)

	1999 Final Rates	Revenue Requirements to Produce 8.33% 2004 Base Year	2004 Nominal Amount (N.1)	2004 BAU Amount	2004 1 + Index	Notes	2005 BAU * Index Amount	2005 Nominal Amount (N.1)	2005 TOTAL RAM Amount	Notes
Electric Sales Revenue	147,068	156,966					0		157,601	N.6
Other Operating Revenue	1,746	1,746	0	1,746	100.0%	N.2	1,746	0	1,746	
Gain on Sale of Land			0	0	100.0%	N.2	0	0	0	
TOTAL OPERATING REVENUES	148,814	158,712	0	1,746			1,746		159,247	
Fuel	41,411	26,488	26,488	0	100.0%	N.2	0	26,488	26,488	
Purchased Power	6,343	11,849	11,849	0	100.0%	N.2	0	11,849	11,849	
Production	15,554	19,263								
Production Labor *	5,888	8,531		8,531	100.5%	N.3	8,573		8,573	
Production NonLabor *	9,666	10,732	0	10,732	102.0%	N.4	10,947	0	10,947	
Transmission	1,118	1,896								
Transmission Labor *	381	645		645	100.5%	N.3	648		648	
Transmission NonLabor *	737	1,251		1,251	102.0%	N.4	1,276		1,276	
Distribution	4,013	5,024								
Distribution Labor *	1,853	2,407		2,407	100.5%	N.3	2,419		2,419	
Distribution NonLabor *	2,160	2,617	0	2,617	102.0%	N.4	2,669	0	2,669	
Customer Accounts	2,083	2,408								
Customer Accounts Labor *	1,360	1,525		1,525	100.5%	N.3	1,532		1,532	
Customer Accounts NonLabor	723	883	0	883	102.0%	N.4	901	0	901	
Allowance for Uncoll. Accounts	0	0		0	102.0%	N.4	0		0	
Customer Service	563	3,599								
Customer Service Labor *	77	314		314	100.5%	N.3	316		316	
Customer Service NonLabor	476	3,285		3,285	102.0%	N.4	3,351		3,351	
Administration & General	7,007	8,267							0	
Admin & Gen Labor *	2,369	2,167		2,167	100.5%	N.3	2,178		2,178	
Admin & Gen NonLabor *	4,638	6,100		6,100	102.0%	N.4	6,222		6,222	
Operation and Maintenance	78,082	78,794	38,337	40,457			41,031		79,368	
Depreciation & Amortization	18,807	24,290	na	na			na		24,290	N.7
Amortization of State ITC	0	0		0	100.0%	N.5	0		0	
Taxes Other Than Income	14,308	15,385	na	na			na		15,247	N.8
Interest on Customer Deposits)	87	0		0	100.0%	N.5	0		0	
Income Taxes	10,270	11,067	na	na			na		11,067	
TOTAL OPERATING EXPENSES	121,554	129,336	38,337	40,457			41,031		129,972	
OPERATING INCOME	27,259	29,375	na	na			na		29,375	
							0			
AVERAGE RATE BASE	310,118	334,190	na	na			na		334,190	
RATE OF RETURN ON AVERAGE RATE BASE	8.79%	8.79%	29,375.3						8.79%	
REVENUE ADJUSTMENT (DIFFERENCE IN TOTAL OPERATING REVENUES)									$636	

	2005 Nominal Amount	2005 BAU Amount	2005 1 + Index	Notes	2006 BAU * Index Amount	2006 Nominal Amount	2006 TOTAL RAM Amount	Notes
Electric Sales Revenue							158,416	N.6
Other Operating Revenue	0	1,746	100.0%	N.2	1,746	0	1,746	
Gain on Sale of Land	0	0	100.0%	N.2	0	0	0	
TOTAL OPERATING REVENUES	0	1,746			1,746		160,162	
Fuel	26,488	0	100.0%	N.2	0	26,488	26,488	
Purchased Power	11,849	0	100.0%	N.2	0	11,849	11,849	
Production								
Production Labor *	0	8,573	102.5%	N.3	8,789		8,789	
Production NonLabor *	0	10,947	102.5%	N.4	11,220	0	11,220	
Transmission								
Transmission Labor *	0	648	102.5%	N.3	664		664	
Transmission NonLabor *	0	1,276	102.5%	N.4	1,308		1,308	
Distribution								
Distribution Labor *	0	2,419	102.5%	N.3	2,480		2,480	
Distribution NonLabor *	0	2,669	102.5%	N.4	2,736	0	2,736	
Customer Accounts								
Customer Accounts Labor *	0	1,532	102.5%	N.3	1,571		1,571	
Customer Accounts NonLabor	0	901	102.5%	N.4	923	0	923	
Allowance for Uncoll. Accounts	0	0	102.5%	N.4	0		0	
Customer Service								
Customer Service Labor *	0	316	102.5%	N.3	323		323	
Customer Service NonLabor	0	3,351	102.5%	N.4	3,434		3,434	
Administration & General	0						0	
Admin & Gen Labor *	0	2,178	102.5%	N.3	2,232		2,232	
Admin & Gen NonLabor *	0	6,222	102.5%	N.4	6,378		6,378	
Operation and Maintenance	38,337	41,031			42,060	38,337	80,397	
Depreciation & Amortization	na	na			na		24,290	N.7
Amortization of State ITC	0	0	100.0%	N.5	0		(726)	
Taxes Other Than Income	na	na			na		15,348	N.8
Interest on Customer Deposits)	0	0	100.0%	N.5	0		411	
Income Taxes	na	na			na		11,067	
TOTAL OPERATING EXPENSES	38,337	41,031			42,060		130,787	
		0			0			
OPERATING INCOME	na	na			0		29,375	
AVERAGE RATE BASE	na	na			na		334,190	
RATE OF RETURN ON AVERAGE RATE BASE	29,375.3						8.79%	29,375.3
REVENUE ADJUSTMENT (DIFFERENCE IN TOTAL OPERATING REVENUES)							$815	

	2006 Nominal Amount	2006 BAU Amount	2006 1 + Index	Notes	2007 BAU * Index Amount	2007 Nominal Amount	2007 TOTAL RAM Amount	Notes
Electric Sales Revenue							159,554	N.6
Other Operating Revenue	0	1,746	100.0%	N.2	1,746	0	1,746	
Gain on Sale of Land	0	0	100.0%	N.2	0	0	0	
TOTAL OPERATING REVENUES	0	1,746			1,746		161,300	
Fuel	26,488	0	100.0%	N.2	0	26,488	26,488	
Purchased Power	11,849	0	100.0%	N.2	0	11,849	11,849	
Production								
Production Labor *	0	8,789	102.9%	N.3	9,039		9,039	
Production NonLabor *	0	11,220	102.1%	N.4	11,456	0	11,456	
Transmission								
Transmission Labor *	0	664	102.9%	N.3	683		683	
Transmission NonLabor *	0	1,308	102.1%	N.4	1,335		1,335	
Distribution								
Distribution Labor *	0	2,480	102.9%	N.3	2,550		2,550	
Distribution NonLabor *	0	2,736	102.1%	N.4	2,794	0	2,794	
Customer Accounts								
Customer Accounts Labor *	0	1,571	102.9%	N.3	1,616		1,616	
Customer Accounts NonLabor	0	923	102.1%	N.4	943	0	943	
Allowance for Uncoll. Accounts	0	0	102.1%	N.4	0		0	
Customer Service								
Customer Service Labor *	0	323	102.9%	N.3	333		333	
Customer Service NonLabor	0	3,434	102.1%	N.4	3,507		3,507	
Administration & General	0						0	
Admin & Gen Labor *	0	2,232	102.9%	N.3	2,296		2,296	
Admin & Gen NonLabor *	0	6,378	102.1%	N.4	6,511	0	6,511	
Operation and Maintenance	38,337	42,060			43,063	38,337	81,400	
Depreciation & Amortization	na	na			na		24,290	N.7
Amortization of State ITC	0	-726	100.0%	N.5	-726		-726	
Taxes Other Than Income	na	na			na		15,482	N.8
Interest on Customer Deposits)	0	411	100.0%	N.5	411		411	
Income Taxes	na	na			na		11,067	
TOTAL OPERATING EXPENSES	38,337	41,745			42,748		131,924	
		0			0		0	
OPERATING INCOME	na	na			0		29,375	
AVERAGE RATE BASE	na	na			na		334,190	
RATE OF RETURN ON AVERAGE RATE BASE							8.79%	29,375.3
REVENUE ADJUSTMENT (DIFFERENCE IN TOTAL OPERATING REVENUES)							$1,138	

* Allocated Labor and Nonlabor of total O&M expenses based on 2006 Budget as provided in HELCO-WP-101(A) in the 2006 Rate Case
** Expenses and Rate Base from 2009 Budget (see L. Matsunaga email dated 1/25/09), Electric Sales Revenues Based on Revenue Requirement formula (see N.6)

N.1 Based on Rate Case Base Year for fuel & purchased power
N.2 No escalator used.
N.3 Escalation based on collective bargaining agreement of 2005=1.25%, 2006=3.28%, 2007=3.61%, 2008=2.91%, 2009=4.0%
See Labor & Nonlabor Escalators worksheet
N.4 Based on Blue Chip Economic Indicators Consensus, GDP Price Index February issue of RAM year"
N.5 Assumes no change in state ITC amount and no growth based on rate base RAM assumption of no growth in customer deposits
N.6 (Total Operating Expenses less revenue taxes+Operating Income)/(1-PUC & PSC & Franchise Tax rates-Uncoll Factor) less Other Operating revenue & Gain on Sale of Land
N.7 Calculated as part of Rate Base RAM, not O&M RAM
N.8 See "Taxes" Tab in Worksheet

Total Base O&M Labor in Test Year

2004	15,589.0	
2005	15,665.4	100.49%
2006	16,060.2	102.52%
2007	16,517.9	102.85%

Total Base O&M NonLabor in Test Year (excluding Fuel, Purchase Power, & Uncollectibles)

2004	24,868.0	
2005	25,365.4	102.00%
2006	25,999.5	102.50%
2007	0	0.00%

Total O&M Labor & NonLabor in Test Year (excluding Fuel, Purchase Power, & Uncollectibles)

2004	40,457.0	
2005	41,030.7	101.42%
2006	42,059.6	102.51%
2007	16,517.9	39.27%

Total Operating Income

2004	29,375.3	
2005	29,375.3	100.00%
2006	29,375.3	100.00%
2007		0.00%

Total O&M Expenses & Operating Income (excluding Fuel, Purchase Power, & Uncollectibles)

2004	69,832.3	
2005	70,406.0	100.82%
2006	71,434.9	101.46%
2007	16,517.9	23.12%

Maui Electric Company, Limited (MECO)

O&M Forecast Only for Revised PUC-IR-14 - Recast 2004-2008
Rate Case -2007 Test Year - Probable Entitlement
($ Thousands)

	2007 Rate Case Interim Rates	Revenue Requirements to Produce 8.33% 2007 Rate Cas Interim Rates	2007 Nominal Amount (N.1)	2007 BAU Amount	2007 1 + Index	Notes	2008 BAU * Index Amount	2008 Nominal Amount (N.1)	2008 TOTAL RAM Amount	Notes	2008 Nominal Amount	2008 BAU Amount	2008 1 + Index	Notes	2009 BAU * Index Amount	2009 Nominal Amount	2009 TOTAL RAM Amount	Notes
Electric Sales Revenue	368,775	368,777					0		370,177	N.6							371,257	N.6
Other Operating Revenue	1,754	1,754	0	1,754	100.0%	N.2	1,754	0	1,754		0	1,754	100.0%	N.2	1,754	0	1,754	
Gain on Sale of Land			0	0	100.0%	N.2	0	0	0		0	0	100.0%	N.2	0	0	0	
TOTAL OPERATING REVENUES	370,529	370,531	0	1,754			1,754		371,931		0	1,754			1,754		373,011	
Fuel	180,465	180,465	180,465	0	100.0%	N.2	0	180,465	180,465		180,465	0	100.0%	N.2	0	180,465	180,465	
Purchased Power	33,982	33,982	33,982	0	100.0%	N.2	0	33,982	33,982		33,982	0	100.0%	N.2	0	33,982	33,982	
Production	20,847	20,847																
Production Labor *	7,891	7,891		7,891	102.2%	N.3	8,061		8,061		0	8,061	103.2%	N.3	8,322		8,322	
Production NonLabor *	12,956	12,956	0	12,956	102.2%	N.4	13,241	0	13,241		0	13,241	101.8%	N.4	13,479	0	13,479	
Transmission	2,093	2,093																
Transmission Labor *	714	714		714	102.2%	N.3	729		729		0	729	103.2%	N.3	753		753	
Transmission NonLabor *	1,379	1,379		1,379	102.2%	N.4	1,409		1,409		0	1,409	101.8%	N.4	1,435		1,435	
Distribution	5,915	5,915																
Distribution Labor *	2,732	2,732		2,732	102.2%	N.3	2,790		2,790		0	2,790	103.2%	N.3	2,881		2,881	
Distribution NonLabor *	3,183	3,183	0	3,183	102.2%	N.4	3,253	0	3,253		0	3,253	101.8%	N.4	3,312	0	3,312	
Customer Accounts	3,017	3,017																
Customer Accounts Labor *	1,969	1,969		1,969	102.2%	N.3	2,011		2,011		0	2,011	103.2%	N.3	2,077		2,077	
Customer Accounts NonLabor	1,048	1,048	0	1,048	102.2%	N.4	1,071	0	1,071		0	1,071	101.8%	N.4	1,090	0	1,090	
Allowance for Uncoll. Accounts	222	222		222	102.2%	N.4	227		227		0	227	101.8%	N.4	231		231	
Customer Service	1,316	1,316																
Customer Service Labor *	183	183		183	102.2%	N.3	187		187		0	187	103.2%	N.3	193		193	
Customer Service NonLabor *	1,133	1,133		1,133	102.2%	N.4	1,158		1,158		0	1,158	101.8%	N.4	1,179		1,179	
Administration & General	13,306	13,306							0		0						0	
Admin & Gen Labor *	4,500	4,500		4,500	102.2%	N.3	4,596		4,596		0	4,596	103.2%	N.3	4,745		4,745	
Admin & Gen NonLabor *	8,806	8,806		8,806	102.2%	N.4	9,000		9,000		0	9,000	101.8%	N.4	9,162		9,162	
Operation and Maintenance	261,163	261,163	214,447	46,716			47,735		262,182		214,447	47,735			48,859	214,447	263,306	
Depreciation & Amortization	28,012	28,012	na	na			na		28,012	N.7	na	na			na		28,012	N.7
Amortization of State ITC	(518)	(518)		-518	100.0%	N.5	-518		-518		0	-518	100.0%	N.5	-518		(726)	
Taxes Other Than Income	34,177	34,177	na	na			na		34,393	N.8	na	na			na		34,533	N.8
Interest on Customer Deposits)	221	221		221	100.0%	N.5	221		386		0	386	100.0%	N.5	386		411	
Income Taxes	14,272	14,272	na	na			na		14,272		na	na			na		14,272	
TOTAL OPERATING EXPENSES	337,327	337,327	214,447	46,419			47,438		338,728		214,447	47,603			48,727		339,808	
												0			0			
OPERATING INCOME	33,203	33,203	na	na			na		33,203		na	na			0		33,203	
							0											
AVERAGE RATE BASE	382,969	382,969	na	na			na		382,969		na	na			na		382,969	
											33,203.4							
RATE OF RETURN ON AVERAGE RATE BASE	8.67%	8.67%	33,204.4						8.67%								8.67%	33,203.4
REVENUE ADJUSTMENT (DIFFERENCE IN TOTAL OPERATING REVENUES)									$1,400								$1,080	

* Allocated Labor and Nonlabor of total O&M expenses based on 2006 Budget as provided in HELCO-WP-101(A) in the 2006 Rate Case

** Expenses and Rate Base from 2009 Budget (see L. Matsunaga email dated 1/25/09), Electric Sales Revenues Based on Revenue Requirement formula (see N.6)

N.1 Based on Rate Case Base Year for fuel & purchased power

N.2 No escalator used.

N.3 Escalation based on collective bargaining agreement of 2005=1.25%, 2006=3.28%, 2007=3.61%, 2008=2.91%, 2009=4.0%

See Labor & Nonlabor Escalators worksheet

N.4 Based on Blue Chip Economic Indicators Consensus, GDP Price Index February issue of RAM year"

N.5 Assumes no change in state ITC amount and no growth based on rate base RAM assumption of no growth in customer deposits

N.6 (Total Operating Expenses less revenue taxes+Operating Income)/(1-PUC & PSC & Franchise Tax rates-Uncoll Factor) less Other Operating revenue & Gain on Sale of Land

N.7 Calculated as part of Rate Base RAM, not O&M RAM

N.8 See "Taxes" Tab in Worksheet

Total Base O&M Labor in Test Year

2007	17,988.8	
2008	18,375.6	102.15%
2009	18,970.9	103.24%

Total Base O&M NonLabor in Test Year (excluding Fuel, Purchase Power, & Uncollectibles)

2007	28,505.2	
2008	29,132.3	102.20%
2009	29,656.7	101.80%

Total O&M Labor & NonLabor in Test Year (excluding Fuel, Purchase Power, & Uncollectibles)

2007	46,494.0	
2008	47,507.9	102.18%
2009	48,627.6	102.36%

Total Operating Income

2007	33,203.4	
2008	33,203.4	100.00%
2009	33,203.4	100.00%

Total O&M Expenses & Operating Income (excluding Fuel, Purchase Power, & Uncollectibles)

2007	79,697.4	
2008	80,711.3	101.27%
2009	81,831.0	101.39%

ATTACHMENT 1
WP-1(c)4
PAGE 5 OF 5

Maui Electric Company, Ltd.
Decoupling-Rate Base RAM Illustration, 2004-2008
(RATE BASE CHANGE)
($000s)

		Actual 12/31/2002 (as needed)	2004 RAM MECO Rate Base -- Average Actual 12/31/03	2004 Changes	RAM Est 12/31/04	2005 RAM Actual 12/31/04	2005 Changes	RAM Est 12/31/05	2006 RAM Actual 12/31/05	2006 Changes	RAM Est 12/31/06	2007 RAM Actual 12/31/06	2007 Changes	RAM Est 12/31/07	2008 RAM Actual 12/31/07	2008 Changes	RAM Est 12/31/08
1	**Net Plant In Service**																
2	Plant in Service:																
3	Starting Balance -Gen'l Accounting / Budget				$ 631,829	$ 631,829		$ 655,935	$ 655,935		$ 679,974	$ 679,974		$ 768,773	$ 768,773		795,399
4						-			-			-			-		
5	Additions, net			$ 23,427	23,427	24,106	$ 23,431	23,431	24,039	$ 25,257	25,257	88,799	$ 26,626	26,626	29,301	$ 27,654	27,654
6	Retirements					-			-			-			-		
7	Ending Balance	597,341	631,829	23,427	655,256	655,935	23,431	679,366	679,974	25,257	705,231	768,773	26,626	795,399	798,074	27,654	823,053
8	Accumulated Depreciation:																
9	Starting Balance - Gen'l Accounting				(262,862)	(262,862)		(286,596)	(286,596)		(312,872)	(312,872)		(340,277)	(340,277)		(368,375)
10	Cost of Removal				-			-			-			-			-
11	Salvage				-			-			-			-			-
12	Depreciation Accrual	(24,353)	(25,357)	(25,715)	(25,715)	(26,835)	(27,025)	(27,025)	(27,572)	(28,491)	(28,491)	(28,385)	(33,134)	(33,134)	(30,910)	(33,998)	(33,998)
13	Retirements			-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Ending Balance (1)	(240,268)	(262,862)	(25,715)	(288,577)	(286,596)	(27,025)	(313,621)	(312,872)	(28,491)	(341,363)	(340,277)	(33,134)	(373,411)	(368,375)	(33,998)	(402,373)
15	Net Plant in Service	357,073	368,967	(2,288)	366,679	369,339	(3,594)	365,745	367,102	(3,234)	363,868	428,496	(6,508)	421,988	429,699	(6,344)	420,680
16	**Deductions**																
17	Unamortized CIAC - Gen'l Accou	(25,508)	(33,879)	(5,555)	(37,776)	(35,142)	(2,613)	(36,003)	(43,421)	(3,712)	(45,056)	(52,701)	(5,587)	(55,842)	(60,310)	(7,238)	(64,793)
17a	Adjustment for CIAC amortization	1,321	1,337	1,658			1,752			2,077			2,446			2,755	
17b	Adjustment for CIAC amortization - incremental portion (2)			-			-			-			-			-	
18	Accumulated Def Income Taxes-Gen'l Acc		(13,626)	(426)	(14,052)	(19,475)	(2,142)	(21,617)	(22,876)	(2,093)	(24,969)	(11,965)	819	(11,146)	(13,749)	(170)	(13,919)
19	Total	(24,187)	(46,168)	(4,323)	(51,828)	(54,617)	(3,003)	(57,620)	(66,297)	(3,728)	(70,025)	(64,666)	(2,322)	(66,988)	(74,059)	(4,653)	(78,712)
20	Net Rate Base (before working ca	$ 332,886	$ 322,799	$ (6,611)	314,851	$ 314,722	$ (6,597)	308,125	$ 300,805	$ (6,962)	293,843	$ 363,830	$ (8,830)	355,000	$ 355,640	(10,997)	$ 341,968
21	Average Rate Base	$ 327,843			$ 318,825			$ 311,424			$ 297,324			$ 359,415			$ 348,804
22	Average Change in Rate Base:		CHANGE IN 2004 RATE BASE			CHANGE IN 2005 RATE BASE			CHANGE IN 2006 RATE BASE			CHANGE IN 2007 RATE BASE			CHANGE IN 2008 RATE BASE		
23	Baseline Additions		$ 19,798			$ 23,431			$ 25,257			$ 26,626			$ 27,654		
24	Major CIP Project Additions (3)		3,629			-			-			-			-		
25	Accumulated Depreciation		(25,715)			(27,025)			(28,491)			(33,134)			(33,998)		
26	Net Plant																
27	ADIT - Baseline		(1,001)			(2,092)			(2,451)			370			262		
28	ADIT - Major CIP		(197)			-			-			-			-		
29	ADIT (CIAC) - Baseline		35			(50)			358			449			(432)		
30	ADIT (CIAC) - Major CIP		737			-			-			-			-		
31	CIAC - Baseline		(2,915)			(2,613)			(3,712)			(5,587)			(7,238)		
32	CIAC - Major CIP		(2,840)		Change in Revenue Requirement	-		Change in Revenue Requirement	-		Change in Revenue Requirement	-		Change in Revenue Requirement	-		Change in Revenue Requirement
33	Total Change in Rate Base					$ (4,755)			$ (5,805)			$ (4,768)			$ (7,408)		
34	Effective Pre-Tax Return	13.43%		13.43%			13.43%			13.43%			13.43%			13.63%	
35	Gross Return on Rate Base	$ 44,029		$ 42,818	$ (1,211)		$ 41,824	$ (994)		$ 39,931	$ (1,894)		$ 48,269	$ 8,339		$ 47,542	$ (727)
36	Income Statement Effects:																
37	Less: CIAC Amortization				(185)			(87)			(124)			(186)			(241)
38	Add: Annualized Prior Year Depreciation				358			190			919			4,749			3,088
39	Revenue Requirement on Plant Additions				$ (1,038)			$ (892)			$ (1,098)			$ 12,902			$ 2,119

(1) Actual cost of removal, salvage and retirements are included in actual ending Accumulated Depreciation balance but are not shown separately above.
(2) For the purposes of estimating the rate base RAM for 2004-2008, Line 17b was not included as Line 17a represent the actual amortization amounts for each year based on beginning of year balances.
(3) One major project ($2.5 million-+) was included in the rate base RAM calculation for 2004-2008 -- the Wailuku Country Estates Subdivision project with an in-service date of April 2004 (Total cost $3,628,684; Dkt. No. 03-0029). Other major projects were completed during this period but were not included in the rate base RAM calculation as they were not completed in January - September of the RAM year (GE Spare Engine with an in-service date of Nov. 2004 (Total cost $3,459,560; Dkt. No. 03-0178) and Maalaea M18 in-service in October 2006 (Total cost $64,810,985; Dkt. No. 7744)). In order to respond in a timely manner, used available project costcost information which is based on the final report filed with the Commission, instead of the PUC-authorized cost information as proposed in this proceeding, for calculating the 2004-2008 rate base RAMs.

Decoupling Docket
Hearing Exhibit - Question 2

HECO Companies' Response:

(a) Summary of Average ROEs presented in PUC-IR-14, page 8

Five Year Average ROE (2009-2013)

Scenario	HECO (N.1)	MECO	HELCO
1. With RAM	[redacted]%	[redacted]%	[redacted]%
2. Without RAM-same cycle	[redacted]%	[redacted]%	[redacted]%
3. Without RAM - More frequent cycle	[redacted]%	[redacted]%	[redacted]%
4. Revenue Per Customer, reset	[redacted]%	[redacted]%	[redacted]%
5. Revenue Per Customer, no reset	[redacted]%	[redacted]%	[redacted]%

Difference from Scenario 1	HECO	MECO	HELCO
1. With RAM	0.00%	0.00%	0.00%
2. Without RAM-same cycle	-0.72%	0.31%	-0.12%
3. Without RAM - More frequent cycle	-0.33%	0.31%	0.17%
4. Revenue Per Customer, reset	-0.87%	0.17%	-0.43%
5. Revenue Per Customer, no reset	-0.90%	0.19%	-0.39%

ROE Baseline			
Currently Proposed ROE (with RAM)	11.0%	10.7%	10.7%
Currently Proposed ROE (without RAM)	11.25%	NA	NA

N.1 For year 2009 included in the scenario analyses above, HECO's ROE was assumed to be 10.5% as agreed upon by the Parties for the Interim Decision (see HECO's Statement of Probable Entitlement, filed on May 18, 2009, in its 2009 test year rate case, Docket No. 2008-0083). For years 2010 to 2013, the analyses for the scenario with RAM was based on HECO's proposed ROE of 11%. The analyses for scenarios without RAM were based on HECO's proposed ROE of 11.25% (assuming no RAM). Further discussion of the Companies' proposed ROE are found in Attachment 1 (the Companies' response to Question 2 of the PUC Hrg. Ex. 1).

Is Decoupling a Disincentive to Energy Efficiency?

On June 30, 2009, during the decoupling panel hearings, Mr. Alan Hee gave an oral explanation of Table 6 on page 8 of NRRI's Scoping Paper , explaining that the payback period for a customer that wants to invest in an energy conservation measure actually decreases when a sales decrease results in a positive sales decoupling adjustment to the unit cost of electricity. Therefore, under this circumstance, sales decoupling can result in increased incentives for energy efficiency. The following is the written explanation as requested by the Commission.

Case 1 of Table 6 assumes that there are only two customers that each consume 500 kwh per year, for a total consumption of 1000 kwh. The cost of a kwh is 10 cents; therefore, each customer's bill is $50. In case 1, without decoupling, a $20 investment by the two customers saves a total of $5 annually, or 50 kwh. Total consumption has decreased to 950 kwh. (Apparently, the two customers are sharing equally the investment and savings of the measure). The payback period is, therefore, the investment cost divided by the savings:

Payback period = $20 ÷ $5 = 4 years

With decoupling of earnings, the two customers receive a decoupling adjustment of $3 since the fixed costs associated with each kwh saved is 6 cents. According to Table 6, the bill savings to both customers is no longer $5, but is $5 less $3, or $2. For the same $20 investment, under decoupling:

Payback period = $20 ÷ $2 = 10 years

Case 2 of Table 6 assumes that there are the same two customers. This time only one customer makes the investment, saves 50 kwh, or $5, and retains all of the bill savings. His/her resulting bill of $45 represents a savings of 10% below the non-conserving customer's bill ($5 ÷ $50 = 10%). The payback period for this conserving customer, without decoupling, is 4 years:

Payback period = $20 ÷ $5 = 4 years

Total consumption has deceased to 950 kwh, but without decoupling, the non-conserving customer's bill is unaffected by the actions of the conserving customer.

With decoupling of earnings, the savings of 50 kwh results in a decoupling adjustment of $3; however, since the resulting consumption of the two customers is different, the assignment of the decoupling adjustment must be made on the basis of the kwh consumed. Therefore, a decoupling adjustment in cents per kwh must be computed.

The decoupling adjustment in cents/kwh is:

Decoupling adjustment = $3 ÷ 950 kwh = $0.00316, or 0.316 cents/kwh

The decoupling adjustment for both customers is:

for the conserving customer = 450 kwh x \$0.00316 = \$1.42
for the non-conserving cust = 500 kwh x \$0.00316 = \$1.58

According to Table 6, the conserving customer's net savings is equal to the savings from the conservation measure less the increase due to the decoupling adjustment and the recalculated payback period is:

Conserving customer's net savings = \$5.00 - \$1.42 = \$3.58

Payback period = \$20 ÷ 3.58 = 5.6 years

However, this NRRI payback period calculation for the conserving customer with decoupling cannot be applied outside of this hypothetical example. First, this example has only two customers. Therefore, it is clear to the conserving customer that the decoupling adjustment of \$1.42 cents is the result of his/her own conservation actions. As a result, it may be reasonable under this hypothetical situation that the conserving customer may include the impact of the decoupling adjustment in the calculation of the payback period.

However, in a real utility system, which has many customers (HECO's system has about 300,000 customers) the decoupling adjustment is not clearly the result of any single customer's energy conservation behavior, but is rather the result of the collective behavior of all customers due to energy conservation, weather, economy, and other variables. Therefore, the conserving customers are unlikely to view the decoupling adjustment as the result of their own actions and include it as an offset to savings in their payback calculations.

Furthermore, the typical payback calculation uses the energy savings from the energy conservation measure times the electricity price as the benefit:

Payback period = investment ÷ savings benefit from the investment

The electricity price under decoupling in the Table 6 example is (10 + 0.316) = 10.316 cents/kwh. Applying this approach to the example in Table 6, the conserving customer, under decoupling, will typically calculate his/her savings as:

Savings = 50 kwh x (10.316) cents/kwh = \$5.16

The payback period is:

Payback period = \$20 ÷ \$5.16 = 3.88 years

This can be compared to the payback period without decoupling of 4 years.

Thus, under decoupling, an increase in the price of electricity resulting from energy efficiency lowers the payback period, making the investment in energy efficiency more attractive not only for the conserving customer, but for non-conserving customers as well.

In addition, note that under decoupling the conserving customer's bill is reduced to \$46.42 (including the decoupling adjustment). The non-conserving customer's bill is \$51.48 (including the decoupling adjustment). The conserving customer's bill remains 10% below the non-conserving customer's bill (\$51.48 – \$46.42 = \$5.06, \$5.06 ÷ \$51.48 = 9.8%), approximately the same 10% savings (with rounding) as he/she saw without decoupling.

Response on Fixed Cost Recovery In Rates

In the HECO Companies' response to the NRRI Scoping paper Appendix 2, question 1, the HECO Companies indicated that approximately 91% of their fixed costs is recovered through volumetric charges. Fixed costs are the sum of customer-related and demand-related costs in the respective rate case cost of service studies that are the basis for the currently effective base rates as authorized in the Companies' last rate cases (HECO test year 2005, HELCO test year 2000, and MECO test year 1999). The volumetric charges are the total revenues from energy charges, demand charges, and other charges based on the amount of energy and demand charges from the final rate designs in those respective rate cases.

At the Decoupling panel hearings, the Department of Business, Economic Development, and Tourism ("DBEDT") shared with the HECO Companies its calculations that were based on the proposed rate designs in the open rate cases: HECO test year 2009, HELCO test year 2006, and MECO test year 2007. The HECO Companies found that the DBEDT calculations correctly compute the percentage share of the proposed energy charges that recover fixed costs.

The HECO Companies provided to DBEDT calculations of the amounts of fixed costs recovered by the customer charge, energy charge, and demand charge elements of the proposed rate design in the HECO TY 2009 direct testimony, by rate schedule, that was prepared in the same manner that the HECO Companies calculated their response to the NRRI Scoping paper Appendix 2, question 1 referenced above (see WP-4a). DBEDT acknowledged that they understood how the calculations were made but has chosen to make a separate submittal to the Commission.

The attached workpaper, WP-4b provides the supporting calculations, by rate schedule, for the HECO Companies' response to the NRRI Scoping paper Appendix 2, question 1 that shows that 91% of the HECO Companies' fixed costs are recovered through volumetric rates. The HECO Companies' volumetric rates are the kWh (energy) charges and the kW (demand) charges, since the amount that customers pay varies directly with the kWh and kW that is used as measured by a billing meter. To the extent that fixed costs are recovered in the per kWh charges, it is clear that reductions in sales will reduce recovery of fixed costs. However, the level of kW usage also varies in conjunction with sales. A customer who installs a more efficient motor or more efficient lighting can reduce both kWh and kW energy use. A reduction in the general level of business, such as a hotel's reduction in the use of air conditioning due to lower occupancy levels can also reduce both kWh and kW energy use. When kWh and kW levels are reduced, energy and demand charges are reduced, and fixed cost recovery is reduced.

Hawaiian Electric Company, Inc.

Rate Design Cost Recovery
Source: HECO-2214, Docket No. 2008-0083

		R	G	J	DS	P	F	Total
	Test Year mWh sales	2,088,400	394,300	2,108,600	1,209,388	1,819,612	37,500	7,657,800
	Rate Design Recovery							
	Customer Charge	$28,299.2	$13,846.4	$7,855.2	$120.0	$1,377.6	$116.4	$51,614.8
	Energy Charge & Adj.	$561,703.5	$103,215.6	$432,233.0	$229,067.3	$355,210.3	$9,900.8	$1,691,330.5
	Energy Charge	$562,351.1	$103,321.6	$434,938.8	$231,515.5	$363,049.0	$9,887.6	$1,705,063.6
	Schedule E	-$660.1	-$105.0	-$384.2	-$133.0	-$241.0	-$8.7	-$1,532.0
	Minimum Bill	$69.3	$0.0	$0.0	$0.0	$0.0	$0.4	$69.7
	Power Factor Adj.	$0.0	$0.0	-$794.7	-$2,315.2	-$3,630.5	$0.0	-$6,740.4
	Apartment House	-$56.8	$0.0	$0.0	$0.0	$0.0	$0.0	-$56.8
	Rider T & Sch U..	$0.0	$0.0	-$648.1	$0.0	-$312.2	$0.0	-$960.3
	Service Voltage Adj.	$0.0	-$1.0	-$878.8	$0.0	-$3,655.0	$21.5	-$4,513.3
	Demand Charge & Adj.	$0.0	$0.0	$96,203.0	$41,345.5	$78,685.1	$0.0	$216,233.6
	Demand Charge	$0.0	$0.0	$97,565.4	$42,661.7	$80,884.0	$0.0	$221,111.1
	Power Factor Adj.	$0.0	$0.0	-$183.9	-$426.6	-$808.8	$0.0	-$1,419.3
	Rider M & Rider I	$0.0	$0.0	-$854.4	-$889.6	-$668.3	$0.0	-$2,412.3
	Service Voltage Adj.	$0.0	$0.0	-$324.1	$0.0	-$721.8	$0.0	-$1,045.9
	Total	$590,002.7	$117,062.0	$536,291.2	$270,532.8	$435,273.0	$10,017.2	$1,959,178.9
	Amounts Recovered By							
L1	Customer Charge	$28,299.2	$13,846.4	$7,855.2	$120.0	$1,377.6	$116.4	$51,614.8
L2	Energy Charge & Adj.	$561,703.5	$103,215.6	$432,233.0	$229,067.3	$355,210.3	$9,900.8	$1,691,330.5
L3	Demand Charge & Adj.	$0.0	$0.0	$96,203.0	$41,345.5	$78,685.1	$0.0	$216,233.6
	Total Rate Design	$590,002.7	$117,062.0	$536,291.2	$270,532.8	$435,273.0	$10,017.2	$1,959,178.9
	Cost of Service Study Allocation of Costs HECO_WP-2203, page 61. Docket No. 2008-0083							
L4	Customer-Related Costs	$75,238.4	$17,196.3	$11,187.7	$248.4	$834.1	$205.0	$104,909.9
L5	Energy-Related Costs	$373,298.4	$70,962.1	$377,917.9	$214,703.4	$325,392.3	$6,581.4	$1,368,855.5
L6	Demand-Related Costs	$141,465.7	$28,904.0	$147,186.4	$55,581.1	$109,046.2	$3,231.1	$485,414.5
	Total Cost of Service	$590,002.5	$117,062.4	$536,292.0	$270,532.9	$435,272.6	$10,017.5	$1,959,179.9
L7 = L4 + L6	Fixed Costs	$216,704.1	$46,100.3	$158,374.1	$55,829.5	$109,880.3	$3,436.1	$590,324.4
	% of Fixed Costs Recovered by:							
L8 = L1 ÷ L7	Customer Charge	13.1%	30.0%	5.0%	0.2%	1.3%	3.4%	8.7%
L9 = (L2-L5) ÷ L7	Energy Charge & Adj.	86.9%	70.0%	34.3%	25.7%	27.1%	96.6%	54.6%
L10 = L6 ÷ L7	Demand Charge & Adj.	0.0%	0.0%	60.7%	74.1%	71.6%	0.0%	36.6%
	Total Fixed Cost Recovery	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Hawaiian Electric Company, Inc.

Rate Design Cost Recovery
Final Rates, Docket No. 04-0113

		R	G	J	H	PT	PP	PS	F	Total
	Test Year mWh sales	2,154,400	377,500	2,013,000	53,400	173,740	2,168,528	875,132	40,300	7,856,000
	Rate Design Recovery									
	Customer Charge	$24,748.1	$12,078.9	$5,478.7	$610.6	$19.2	$796.4	$798.4	$97.4	$44,627.7
	Energy Charge & Adj.	$370,052.8	$61,878.1	$260,581.8	$7,166.0	$19,043.3	$248,401.1	$101,806.4	$6,650.3	$1,075,579.8
	Energy Charge	$370,332.7	$61,987.4	$262,615.5	$7,172.3	$19,168.5	$251,040.5	$102,633.0	$6,640.7	$1,081,590.6
	Schedule E	-$443.0	-$66.1	-$207.7	-$6.3	-$10.2	-$168.2	-$76.2	-$6.2	-$983.9
	Minimum Bill	$237.6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$237.6
	Power Factor Adj.	$0.0	$0.0	-$475.7	$0.0	-$115.0	-$2,510.4	-$923.7	$0.0	-$4,024.8
	Apartment House	-$65.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$65.1
	Rider T & Sch U..	-$9.4	-$43.0	-$819.8	$0.0	$0.0	$0.0	-$3.8	$0.0	-$876.0
	Service Voltage Adj.	$0.0	-$0.2	-$530.5	$0.0	$0.0	$39.2	$177.1	$15.8	-$298.6
	Demand Charge & Adj.	$0.0	$0.0	$56,380.8	$957.8	$4,038.9	$54,714.3	$26,320.1	$0.0	$142,412.0
	Demand Charge	$0.0	$0.0	$57,301.0	$957.8	$4,063.3	$56,816.9	$26,646.1	$0.0	$145,785.1
	Power Factor Adj.	$0.0	$0.0	-$111.5	$0.0	-$24.4	-$568.2	-$239.8	$0.0	-$943.8
	Rider M & Rider I	$0.0	$0.0	-$646.4	$0.0	$0.0	-$1,543.5	-$136.4	$0.0	-$2,326.3
	Service Voltage Adj.	$0.0	$0.0	-$162.3	$0.0	$0.0	$9.0	$50.3	$0.0	-$103.0
	Total	$394,800.9	$73,957.0	$322,441.3	$8,734.4	$23,101.4	$303,911.7	$128,925.0	$6,747.7	$1,262,619.4
	Amounts Recovered By									
L1	Customer Charge	$24,748.1	$12,078.9	$5,478.7	$610.6	$19.2	$796.4	$798.4	$97.4	$44,627.7
L2	Energy Charge & Adj.	$370,052.8	$61,878.1	$260,581.8	$7,166.0	$19,043.3	$248,401.1	$101,806.4	$6,650.3	$1,075,579.8
L3	Demand Charge & Adj.	$0.0	$0.0	$56,380.8	$957.8	$4,038.9	$54,714.3	$26,320.1	$0.0	$142,412.0
	Total Rate Design	$394,800.9	$73,957.0	$322,441.3	$8,734.4	$23,101.4	$303,911.7	$128,925.0	$6,747.7	$1,262,619.4
	Cost of Service Study Allocation of Costs									
L4	Customer-Related Costs	$56,525.5	$12,643.2	$8,981.5	$610.4	$29.1	$1,146.1	$889.1	$99.7	$80,924.6
L5	Energy-Related Costs	$208,721.4	$36,732.5	$195,742.1	$5,188.0	$16,318.4	$204,815.7	$84,611.1	$3,800.2	$755,929.4
L6	Demand-Related Costs	$129,553.6	$24,581.2	$117,717.4	$2,936.1	$6,753.9	$97,950.0	$43,424.9	$2,847.7	$425,764.8
	Total Cost of Service	$394,800.5	$73,956.9	$322,441.0	$8,734.5	$23,101.4	$303,911.8	$128,925.1	$6,747.6	$1,262,618.8
L7 = L4 + L6	Fixed Costs	$186,079.1	$37,224.4	$126,698.9	$3,546.5	$6,783.0	$99,096.1	$44,314.0	$2,947.4	$506,689.4
	% of Fixed Costs Recovered by:									
L8 = L1 ÷ L7	Customer Charge	13.3%	32.4%	4.3%	17.2%	0.3%	0.8%	1.8%	3.3%	8.8%
L9 = (L2-L5) ÷ L7	Energy Charge & Adj.	86.7%	67.6%	51.2%	55.8%	40.2%	44.0%	38.8%	96.7%	63.1%
L10 = L6 ÷ L7	Demand Charge & Adj.	0.0%	0.0%	44.5%	27.0%	59.5%	55.2%	59.4%	0.0%	28.1%
	Total Fixed Cost Recovery	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Hawaii Electric Light Company, Inc.

Rate Design Cost Recovery
Final Rates, Docket No. 99-0207

		R	G	J	H	P	F	Total
	Test Year mWh sales	350,900	77,800	242,300	24,200	236,800	3,800	935,800
	Rate Design Recovery							
	Customer Charge	$6,327.2	$3,341.1	$795.6	$163.4	$283.5	$0.0	$10,910.8
	Energy Charge & Adj.	$67,124.4	$16,589.7	$37,483.5	$3,847.0	$31,135.8	$738.0	$156,918.4
	Energy Charge	$67,151.7	$16,618.4	$37,817.8	$3,852.4	$32,614.6	$731.9	$158,786.8
	Schedule E	-$119.7	-$28.7	-$41.6	-$5.4	-$29.8	-$0.7	-$225.9
	Minimum Bill	$134.6	$0.0	$0.0	$0.0	$0.0	$6.8	$141.4
	Power Factor Adj.	$0.0	$0.0	-$7.0	$0.0	-$440.3	$0.0	-$447.3
	Apartment House	-$42.2	$0.0	$0.0	$0.0	$0.0	$0.0	-$42.2
	Rider T & Sch U..	$0.0	$0.0	-$132.7	$0.0	$0.0	$0.0	-$132.7
	Service Voltage Adj.	$0.0	$0.0	-$153.0	$0.0	-$1,008.7	$0.0	-$1,161.7
	Demand Charge & Adj.	$0.0	$0.0	$5,753.8	$651.1	$5,026.8	$0.0	$11,431.7
	Demand Charge	$0.0	$0.0	$6,281.4	$651.1	$5,543.4	$0.0	$12,475.9
	Power Factor Adj.	$0.0	$0.0	-$1.1	$0.0	-$74.8	$0.0	-$75.9
	Rider M & Rider I	$0.0	$0.0	-$499.8	$0.0	-$272.2	$0.0	-$772.0
	Service Voltage Adj.	$0.0	$0.0	-$26.7	$0.0	-$169.6	$0.0	-$196.3
	Total	$73,451.6	$19,930.8	$44,032.8	$4,661.5	$36,446.1	$738.0	$179,260.9
	Amounts Recovered By							
L1	Customer Charge	$6,327.2	$3,341.1	$795.6	$163.4	$283.5	$0.0	$10,910.8
L2	Energy Charge & Adj.	$67,124.4	$16,589.7	$37,483.5	$3,847.0	$31,135.8	$738.0	$156,918.4
L3	Demand Charge & Adj.	$0.0	$0.0	$5,753.8	$651.1	$5,026.8	$0.0	$11,431.7
	Total Rate Design	$73,451.6	$19,930.8	$44,032.8	$4,661.5	$36,446.1	$738.0	$179,260.9
	Cost of Service Study Allocation of Costs							
L4	Customer-Related Costs	$15,045.9	$4,833.9	$1,850.7	$263.9	$395.9	$29.2	$22,419.5
L5	Energy-Related Costs	$27,888.7	$6,192.1	$19,247.6	$1,924.8	$18,408.4	$302.5	$73,964.1
L6	Demand-Related Costs	$30,517.0	$8,904.8	$22,934.6	$2,472.8	$17,641.8	$406.3	$82,877.3
	Total Cost of Service	$73,451.6	$19,930.8	$44,032.9	$4,661.5	$36,446.1	$738.0	$179,260.9
L7 = L4 + L6	Fixed Costs	$45,562.9	$13,738.7	$24,785.3	$2,736.7	$18,037.7	$435.5	$105,296.8
	% of Fixed Costs Recovered by:							
L8 = L1 ÷ L7	Customer Charge	13.9%	24.3%	3.2%	6.0%	1.6%	0.0%	10.4%
L9 = (L2-L5) ÷ L7	Energy Charge & Adj.	86.1%	75.7%	73.6%	70.2%	70.6%	100.0%	78.8%
L10 = L6 ÷ L7	Demand Charge & Adj.	0.0%	0.0%	23.2%	23.8%	27.9%	0.0%	10.9%
	Total Fixed Cost Recovery	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Maui Electric Company, Ltd. - Maui Division

Rate Design Cost Recovery
Final Rates, Docket No. 97-0346

		R	G	J	H	P	F	Total
	Test Year mWh sales	339,841	80,800	209,849	25,633	341,312	4,663	1,002,098
	Rate Design Recovery							
	Customer Charge	$3,992.5	$1,836.5	$635.9	$133.1	$288.9	$0.0	$6,886.9
	Energy Charge & Adj.	$45,424.0	$11,785.2	$24,804.9	$3,063.8	$32,865.2	$591.7	$118,534.8
	Energy Charge	$45,617.2	$11,769.0	$24,930.5	$3,067.6	$33,539.5	$590.3	$119,514.1
	Schedule E	-$62.2	-$13.8	-$24.3	-$3.8	-$29.8	-$1.6	-$135.5
	Minimum Bill	$79.9	$30.0	$0.0	$0.0	$0.0	$3.0	$112.9
	Power Factor Adj.	$0.0	$0.0	-$4.1	$0.0	-$301.9	$0.0	-$305.9
	Apartment House	-$210.9	$0.0	$0.0	$0.0	$0.0	$0.0	-$210.9
	Rider T & Sch U..	$0.0	$0.0	-$86.6	$0.0	-$5.3	$0.0	-$91.9
	Service Voltage Adj.	$0.0	$0.0	-$10.6	$0.0	-$337.3	$0.0	-$347.9
	Demand Charge & Adj.	$0.0	$0.0	$3,927.2	$408.6	$5,711.6	$0.0	$10,047.4
	Demand Charge	$0.0	$0.0	$4,321.9	$408.6	$6,196.1	$0.0	$10,926.6
	Power Factor Adj.	$0.0	$0.0	-$1.2	$0.0	-$55.8	$0.0	-$56.9
	Rider M & Rider I	$0.0	$0.0	-$391.5	$0.0	-$365.5	$0.0	-$757.0
	Service Voltage Adj.	$0.0	$0.0	-$2.0	$0.0	-$63.3	$0.0	-$65.3
	Total	$49,416.5	$13,621.7	$29,368.1	$3,605.5	$38,865.7	$591.7	$135,469.1
	Amounts Recovered By							
L1	Customer Charge	$3,992.5	$1,836.5	$635.9	$133.1	$288.9	$0.0	$6,886.9
L2	Energy Charge & Adj.	$45,424.0	$11,785.2	$24,804.9	$3,063.8	$32,865.2	$591.7	$118,534.8
L3	Demand Charge & Adj.	$0.0	$0.0	$3,927.2	$408.6	$5,711.6	$0.0	$10,047.4
	Total Rate Design	$49,416.5	$13,621.7	$29,368.1	$3,605.5	$38,865.7	$591.7	$135,469.1
	Cost of Service Study Allocation of Costs							
L4	Customer-Related Costs	$8,584.2	$2,071.0	$861.0	$273.0	$437.4	$254.7	$12,481.3
L5	Energy-Related Costs	$15,759.8	$3,766.8	$9,789.7	$1,193.6	$15,726.7	$213.9	$46,450.5
L6	Demand-Related Costs	$25,072.4	$7,783.9	$18,717.5	$2,139.0	$22,701.6	$123.1	$76,537.5
	Total Cost of Service	$49,416.4	$13,621.7	$29,368.2	$3,605.6	$38,865.7	$591.7	$135,469.3
L7 = L4 + L6	Fixed Costs	$33,656.6	$9,854.9	$19,578.5	$2,412.0	$23,139.0	$377.8	$89,018.8
	% of Fixed Costs Recovered by:							
L8 = L1 ÷ L7	Customer Charge	11.9%	18.6%	3.2%	5.5%	1.2%	0.0%	7.7%
L9 = (L2-L5) ÷ L7	Energy Charge & Adj.	88.1%	81.4%	76.7%	77.5%	74.1%	100.0%	81.0%
L10 = L6 ÷ L7	Demand Charge & Adj.	0.0%	0.0%	20.1%	16.9%	24.7%	0.0%	11.3%
	Total Fixed Cost Recovery	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Maui Electric Company, Ltd. - Lanai Division

Rate Design Cost Recovery
Final Rates, Docket No. 97-0346

		R	G	J	H	P	F	Total
	Test Year mWh sales	6,654	1,540	5,759	545	11,798	118	26,414
	Rate Design Recovery							
	Customer Charge	$108.5	$42.0	$16.3	$1.8	$4.8	$0.0	$173.4
	Energy Charge & Adj.	$1,203.5	$315.2	$1,159.8	$98.0	$2,052.3	$21.9	$4,850.8
	Energy Charge	$1,202.0	$314.4	$1,160.2	$98.1	$1,715.2	$21.9	$4,511.8
	Schedule E	-$1.4	-$0.2	-$0.6	-$0.1	-$1.1	$0.0	-$3.4
	Minimum Bill	$2.9	$1.0	$0.0	$0.0	$0.0	$0.0	$3.9
	Power Factor Adj.	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.2
	Apartment House	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	Rider T & Sch U..	$0.0	$0.0	$0.0	$0.0	$364.4	$0.0	$364.4
	Service Voltage Adj.	$0.0	$0.0	$0.0	$0.0	-$26.2	$0.0	-$26.2
	Demand Charge & Adj.	$0.0	$0.0	$133.7	$5.5	$158.6	$0.0	$297.7
	Demand Charge	$0.0	$0.0	$133.6	$5.5	$161.0	$0.0	$300.1
	Power Factor Adj.	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.1
	Rider M & Rider I	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	Service Voltage Adj.	$0.0	$0.0	$0.0	$0.0	-$2.4	$0.0	-$2.4
	Total	$1,312.0	$357.2	$1,309.8	$105.3	$2,215.7	$21.9	$5,321.9
	Amounts Recovered By							
L1	Customer Charge	$108.5	$42.0	$16.3	$1.8	$4.8	$0.0	$173.4
L2	Energy Charge & Adj.	$1,203.5	$315.2	$1,159.8	$98.0	$2,052.3	$21.9	$4,850.8
L3	Demand Charge & Adj.	$0.0	$0.0	$133.7	$5.5	$158.6	$0.0	$297.7
	Total Rate Design	$1,312.0	$357.2	$1,309.8	$105.3	$2,215.7	$21.9	$5,321.9
	Cost of Service Study Allocation of Costs							
L4	Customer-Related Costs	$222.9	$57.2	$22.7	$2.3	$3.9	$10.4	$319.4
L5	Energy-Related Costs	$603.4	$141.2	$530.6	$50.0	$1,064.6	$10.6	$2,400.4
L6	Demand-Related Costs	$485.8	$158.8	$756.6	$53.0	$1,147.2	$0.9	$2,602.3
	Total Cost of Service	$1,312.1	$357.2	$1,309.9	$105.3	$2,215.7	$21.9	$5,322.1
L7 = L4 + L6	Fixed Costs	$708.7	$216.0	$779.3	$55.3	$1,151.1	$11.3	$2,921.7
	% of Fixed Costs Recovered by:							
L8 = L1 ÷ L7	Customer Charge	15.3%	19.4%	2.1%	3.3%	0.4%	0.0%	5.9%
L9 = (L2-L5) ÷ L7	Energy Charge & Adj.	84.7%	80.6%	80.7%	86.8%	85.8%	100.0%	83.9%
L10 = L6 ÷ L7	Demand Charge & Adj.	0.0%	0.0%	17.2%	9.9%	13.8%	0.0%	10.2%
	Total Fixed Cost Recovery	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Maui Electric Company, Ltd. - Molokai Division

Rate Design Cost Recovery
Final Rates, Docket No. 97-0346

		R	G	J	H	P	F	Total
	Test Year mWh sales	13,012	3,369	9,250	2,256	6,531	497	34,915
	Rate Design Recovery							
	Customer Charge	$215.9	$115.6	$28.2	$9.9	$10.8	$0.0	$380.4
	Energy Charge & Adj.	$2,264.2	$803.1	$1,561.6	$317.3	$874.5	$88.3	$5,909.0
	Energy Charge	$2,269.0	$801.6	$1,564.0	$318.0	$884.6	$88.5	$5,925.7
	Schedule E	-$7.3	-$1.7	-$2.4	-$0.7	-$2.0	-$0.2	-$14.3
	Minimum Bill	$7.2	$3.2	$0.0	$0.0	$0.0	$0.0	$10.4
	Power Factor Adj.	$0.0	$0.0	$0.0	$0.0	-$2.4	$0.0	-$2.4
	Apartment House	-$4.7	$0.0	$0.0	$0.0	$0.0	$0.0	-$4.7
	Rider T & Sch U..	$0.0	$0.0	$0.0	$0.0	-$3.8	$0.0	-$3.8
	Service Voltage Adj.	$0.0	$0.0	$0.0	$0.0	-$1.9	$0.0	-$1.9
	Demand Charge & Adj.	$0.0	$0.0	$150.7	$37.8	$31.4	$0.0	$219.9
	Demand Charge	$0.0	$0.0	$150.7	$37.8	$96.4	$0.0	$284.9
	Power Factor Adj.	$0.0	$0.0	$0.0	$0.0	-$0.3	$0.0	-$0.3
	Rider M & Rider I	$0.0	$0.0	$0.0	$0.0	-$64.5	$0.0	-$64.5
	Service Voltage Adj.	$0.0	$0.0	$0.0	$0.0	-$0.2	$0.0	-$0.2
	Total	$2,480.1	$918.7	$1,740.5	$365.0	$916.7	$88.3	$6,509.3
	Amounts Recovered By							
L1	Customer Charge	$215.9	$115.6	$28.2	$9.9	$10.8	$0.0	$380.4
L2	Energy Charge & Adj.	$2,264.2	$803.1	$1,561.6	$317.3	$874.5	$88.3	$5,909.0
L3	Demand Charge & Adj.	$0.0	$0.0	$150.7	$37.8	$31.4	$0.0	$219.9
	Total Rate Design	$2,480.1	$918.7	$1,740.5	$365.0	$916.7	$88.3	$6,509.3
	Cost of Service Study Allocation of Costs							
L4	Customer-Related Costs	$463.8	$131.7	$32.9	$13.1	$8.9	$14.2	$664.6
L5	Energy-Related Costs	$703.6	$183.2	$502.6	$122.2	$350.4	$26.9	$1,888.9
L6	Demand-Related Costs	$1,312.7	$603.8	$1,205.1	$229.8	$557.4	$47.2	$3,956.0
	Total Cost of Service	$2,480.1	$918.7	$1,740.6	$365.1	$916.7	$88.3	$6,509.5
L7 = L4 + L6	Fixed Costs	$1,776.5	$735.5	$1,238.0	$242.9	$566.3	$61.4	$4,620.6
	% of Fixed Costs Recovered by:							
L8 = L1 ÷ L7	Customer Charge	12.2%	15.7%	2.3%	4.1%	1.9%	0.0%	8.2%
L9 = (L2-L5) ÷ L7	Energy Charge & Adj.	87.8%	84.3%	85.5%	80.3%	92.5%	100.0%	87.0%
L10 = L6 ÷ L7	Demand Charge & Adj.	0.0%	0.0%	12.2%	15.6%	5.5%	0.0%	4.8%
	Total Fixed Cost Recovery	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Hawaiian Electric Company, Inc.

AVOIDED ENERGY COST RATES
ADJUSTED FOR FUEL PRICES EFFECTIVE JUNE 1, 2009

Line		On-Peak	Off-Peak	
(1)	Avoided Fuel Cost	11.436	7.325	¢/kwh
(2)	Avoided O&M Cost	0.060	0.027	¢/kwh
(3)	Avoided Working Cash	0.106	0.068	¢/kwh
(4)	Avoided Fuel Inventory	0.146	0.146	¢/kwh
(5)	Total Avoided Energy Cost Rates	11.748	7.566	¢/kwh

Total Weighted Avoided energy Cost Rate*	10.006	¢/kwh

* Weighted 14/24 On-peak, 10/24 Off-peak

Hawaiian Electric Company, Inc.

AVOIDED ENERGY COST RATES
ADJUSTED FOR FUEL PRICES EFFECTIVE - September 1, 2008

Line		On-Peak	Off-Peak	
(1)	Avoided Fuel Cost	25.614	21.076	¢/kwh
(2)	Avoided O&M Cost	0.059	0.029	¢/kwh
(3)	Avoided Working Cash	0.238	0.196	¢/kwh
(4)	Avoided Fuel Inventory	0.138	0.138	¢/kwh
(5)	Total Avoided Energy Cost Rates	26.049	21.439	¢/kwh
	Total Weighted Avoided energy Cost Rate*	24.128		¢/kwh

* Weighted 14/24 On-peak, 10/24 Off-peak

Hawaii Electric Light Company, Inc

AVOIDED ENERGY COST RATES
ADJUSTED FOR FUEL PRICES EFFECTIVE June 1, 2009

Line		On-Peak	Off-Peak	
(1)	Avoided Fuel Cost	12.536	10.075	¢/kwh
(2)	Avoided O&M Cost	0.619	0.206	¢/kwh
(3)	Avoided Working Cash	0.087	0.070	¢/kwh
(4)	Avoided Fuel Inventory	0.096	0.096	¢/kwh
(5)	Total Avoided Energy Cost Rates	13.338	10.447	¢/kwh

Total Weighted Avoided energy Cost Rate* 12.133 ¢/kwh

* Weighted 14/24 On-peak, 10/24 Off-peak

Hawaii Electric Light Company, Inc

AVOIDED ENERGY COST RATES
ADJUSTED FOR FUEL PRICES EFFECTIVE September 1, 2008
(Revised 7/30/08)

Line		On-Peak	Off-Peak	
(1)	Avoided Fuel Cost	26.517	21.061	¢/kwh
(2)	Avoided O&M Cost	0.400	0.207	¢/kwh
(3)	Avoided Working Cash	0.183	0.146	¢/kwh
(4)	Avoided Fuel Inventory	0.092	0.092	¢/kwh
(5)	Total Avoided Energy Cost Rates	27.192	21.506	¢/kwh

Total Weighted Avoided energy Cost Rate*	24.823	¢/kwh

* Weighted 14/24 On-peak, 10/24 Off-peak

Maui Electric Light Company, Ltd .
MAUI DIVISION
AVOIDED ENERGY COST RATES
ADJUSTED FOR FUEL PRICES EFFECTIVE June 1, 2009

Line		On-Peak	Off-Peak	
(1)	Avoided Fuel Cost	9.970	9.650	¢/kwh
(2)	Avoided O&M Cost	0.266	0.243	¢/kwh
(3)	Avoided Working Cash	0.097	0.093	¢/kwh
(4)	Avoided Fuel Inventory	0.151	0.151	¢/kwh
(5)	Total Avoided Energy Cost Rates	10.484	10.137	¢/kwh
(6)	Total Weighted Avoided energy Cost Rate*		10.339	¢/kwh

* Weighted 14/24 On-peak, 10/24 Off-peak

Maui Electric Light Company, Ltd .
MAUI DIVISION
AVOIDED ENERGY COST RATES
ADJUSTED FOR FUEL PRICES EFFECTIVE September 1, 2008

Line		On-Peak	Off-Peak	
(1)	Avoided Fuel Cost	25.005	23.289	¢/kwh
(2)	Avoided O&M Cost	0.279	0.227	¢/kwh
(3)	Avoided Working Cash	0.243	0.225	¢/kwh
(4)	Avoided Fuel Inventory	0.153	0.153	¢/kwh
(5)	Total Avoided Energy Cost Rates	25.680	23.894	¢/kwh
(6)	Total Weighted Avoided energy Cost Rate*		24.936	¢/kwh

* Weighted 14/24 On-peak, 10/24 Off-peak

Maui Electric Company, Ltd .
LANAI DIVISION
AVOIDED ENERGY COST RATES
ADJUSTED FOR FUEL PRICES EFFECTIVE June 1, 2009

Line		On-Peak	Off-Peak	
(1)	Avoided Fuel Cost	19.138	14.337	¢/kwh
(2)	Avoided O&M Cost	0.856	0.718	¢/kwh
(3)	Avoided Working Cash	0.110	0.083	¢/kwh
(4)	Avoided Fuel Inventory	0.452	0.452	¢/kwh
(5)	Total Avoided Energy Cost Rates	20.556	15.590	¢/kwh
(6)	Total Weighted Avoided Energy Cost Rate*	18.487		¢/kwh

* Weighted 14/24 On-peak, 10/24 Off-peak

Maui Electric Company, Ltd .
LANAI DIVISION
AVOIDED ENERGY COST RATES
ADJUSTED FOR FUEL PRICES EFFECTIVE September 1, 2008

Line		On-Peak	Off-Peak	
(1)	Avoided Fuel Cost	41.768	31.290	¢/kwh
(2)	Avoided O&M Cost	0.816	0.684	¢/kwh
(3)	Avoided Working Cash	0.227	0.171	¢/kwh
(4)	Avoided Fuel Inventory	0.452	0.452	¢/kwh
(5)	Total Avoided Energy Cost Rates	43.263	32.597	¢/kwh
(6)	Total Weighted Avoided Energy Cost Rate*	38.819		¢/kwh

* Weighted 14/24 On-peak, 10/24 Off-peak

Maui Electric Company, Ltd .
MOLOKAI DIVISION
AVOIDED ENERGY COST RATES
ADJUSTED FOR FUEL PRICES EFFECTIVE June 1, 2009

Line		On-Peak	Off-Peak	
(1)	Avoided Fuel Cost	13.643	11.996	¢/kwh
(2)	Avoided O&M Cost	0.730	1.004	¢/kwh
(3)	Avoided Working Cash	0.103	0.096	¢/kwh
(4)	Avoided Fuel Inventory	0.392	0.392	¢/kwh
(5)	Total Avoided Energy Cost Rates	14.868	13.488	¢/kwh
(6)	Total Weighted Avoided Energy Cost Rate*	14.293		¢/kwh

* Weighted 14/24 On-peak, 10/24 Off-peak

Maui Electric Company, Ltd .
MOLOKAI DIVISION
AVOIDED ENERGY COST RATES
ADJUSTED FOR FUEL PRICES EFFECTIVE September 1, 2008

Line		On-Peak	Off-Peak	
(1)	Avoided Fuel Cost	33.372	29.347	¢/kwh
(2)	Avoided O&M Cost	0.696	0.957	¢/kwh
(3)	Avoided Working Cash	0.239	0.215	¢/kwh
(4)	Avoided Fuel Inventory	0.392	0.392	¢/kwh
(5)	Total Avoided Energy Cost Rates	34.699	30.911	¢/kwh
(6)	Total Weighted Avoided Energy Cost Rate*	33.121		¢/kwh

* Weighted 14/24 On-peak, 10/24 Off-peak

ECAC Heat Rate Comparison

	Fuel Expense ($000)			
	Actual	Recovered	Recv less Actual	
HECO				
2004	327,376	327,550	174	
2005	416,073	412,548	-3,525	
2006	510,859	511,768	909	
2007	518,937	514,037	-4,900	
2008	856,990	863,763	6,773	
Total	2,630,235	2,629,666	-569	
HELCO				
2004	38,117	37,696	-421	
2005	65,272	65,144	-128	
2006	85,229	82,510	-2,719	
2007	74,964	72,914	-2,050	
2008	109,618	105,179	-4,439	
Total	373,200	363,443	-9,757	
MECO				
2004	110,044	109,021	-1,023	
2005	153,832	151,889	-1,943	
2006	180,232	176,181	-4,051	
2007	173,130	176,003	2,873	
2008	252,076	255,184	3,108	
Total	869,314	868,278	-1,036	(Revised)
Total				
2004	475,537	474,267	-1,270	
2005	635,177	629,581	-5,596	
2006	776,320	770,459	-5,861	
2007	767,031	762,954	-4,077	
2008	1,218,684	1,224,126	5,442	
Total	3,872,749	3,861,387	-11,362	

Source: 4th quarter ECA reconcilation summary, lines 1 and 5.

REVISED SHEET NO. __
Effective January 1,2010

RATE ADJUSTMENT MECHANISM PROVISION

ILLUSTRATIVE EXAMPLE FOR HAWAIIAN ELECTRIC COMPANY, INC.

Rate Adjustment Mechanism ("RAM") Provision

Purpose

This mechanism is subject to review and continuation, termination or modification in the utility's next base rate case proceeding, upon a showing by the utility and finding by the Commission that continuation or modification is appropriate. As part of its submitted testimony in the base rate case, the Company will include a summary report on the status of certain HCEI initiatives. The RAM mechanism is designed to determine the change in annual utility base revenue levels, recognizing certain estimated changes in the utility's cost to provide service. If, through the application of this mechanism, it is determined that annual utility base revenues should be decreased or increased, then the RAM Revenue Adjustment will be applied within the Revenue Balancing Account Provision. The RAM Revenue Adjustment established for RAM Period calendar year 2011 shall remain in effect until the Commission approves a base revenue level in the Company's 2011 test year rate application.

Definitions

a) The **Annual Evaluation Date** shall be the Date the Company will make its annual filing under this mechanism. The Annual Evaluation Date shall be no later than March 31, of each year commencing March 31, 2010.

b) The **Evaluation Period** is defined as the historical twelve month period ending December 31, of each calendar year preceding the Annual Evaluation Date. The Evaluation Period is used solely to determine achieved earnings and any sharing of such earnings above the Authorized Return on Equity.

c) The **RAM Period** is defined as the calendar year containing the Annual Evaluation Date.

d) The **Labor Cost Escalation Rate** shall be the applicable annual percentage general wage rate increase provided for in currently effective union labor agreements for use in escalating

RATE ADJUSTMENT MECHANISM

wage and salary Base Expenses for both union and non-union employees to determine the RAM Revenue Adjustment for each RAM Period. In the event no union labor agreement exists for a RAM Period, the most recently effective annual general percentage increase rate shall apply.

e) The **Non-labor Cost Escalation Rate** shall be the consensus estimated annual change in the Gross Domestic Product Price Indicator ("GDPPI") to escalate non-labor Base Expenses to determine the RAM Revenue Adjustment for each RAM Period. The GDPPI escalation rate shall be the consensus projection published by the Blue Chip Economic Indicators (Aspen Publishing) each February for the current Rate Adjustment Period. In the event that the Blue Chip Economic Indicators forecast of the GDPPI is not available, the Consumer Advocate, Company, and other parties to the most recent rate case, with approval of the Commission, shall jointly select an alternative data source, or national economic index similar to GDPPI, as appropriate.

f) The annual **Labor Productivity Offset** shall be fixed at 0.76 percent (76/100 of one percent) and will be subtracted from the Labor Cost Escalation Rates applicable to Base Expenses to determine the authorized RAM Revenue Adjustment for each RAM Period.

g) The **Base Expenses** shall be the labor and non-labor operations and maintenance expense amounts approved by the Commission in the most recently completed rate case where the test year was the Evaluation Period, or alternatively as approved by the Commission for the immediately preceding year Rate Adjustment Mechanism results if the Evaluation Period was not a test year. Base Expenses shall not include any fuel, purchased power, IRP/DSM, pension, Other Post Employment Benefits ("OPEB"), or Clean Energy/Renewable Energy Infrastructure costs that are subject to recovery through separate rate tracking mechanisms.

h) The **Major Capital Projects** shall be those capital investment projects that require application and Commission approval under the Commission's General Order No. 7, but

RATE ADJUSTMENT MECHANISM PROVISION

excluding those projects included in the Clean Energy Infrastructure Surcharge.

i) The **Baseline Capital Projects** shall be the total amounts of capital investment completed and closed to Plant in Service, excluding amounts related to Major Capital Projects.

j) The **Return on Investment** shall be the overall weighted percentage rate of return on debt and equity capital approved by the Commission in the most recently completed rate case.

k) The **Authorized Return on Equity** shall be the overall weighted percentage rate of return on equity capital approved by the Commission in the most recently completed rate case.

l) The **Exogenous Tax Changes** shall be the changes in tax laws or regulations that are estimated to impact Authorized Base Rate Revenues by two million dollars ($2,000,000) or more.

m) The **Rate Base** shall be the average net investment estimated for the RAM Period, including each of the elements of rate base reflected within the most recent rate case Decision & Order issued by the Commission, quantified in the manner prescribed in part (f) of Section 2 of the Rate Adjustment Mechanism.

n) The **Authorized Base Revenue** shall be the annual amount of revenue required for the utility to recover its estimated Operations & Maintenance, Depreciation, Amortization and Tax expenses for the RAM Period, as well as the Return on Investment on projected Rate Base for the RAM Period, using the ratemaking conventions and calculations reflected within the most recent rate case Decision & Order issued by the Commission, quantified in the manner prescribed herein.

o) The **RAM Revenue Adjustment** shall be the difference between the calculated Authorized Base Revenue for the RAM Period and either: 1) the previous year's calculated Authorized Base Revenue; or 2) the revenue requirement approved by the Commission in an interim or final decision in the Company's general rate case, whichever is more recent. The RAM Revenue Adjustment determined by this RAM Provision is to be recovered

RATE ADJUSTMENT MECHANISM

through the RBA Provision commencing on June 1 and over the subsequent 12 months after June 1.

p) **Earnings Sharing Revenue Credits** shall be the amounts to be returned to customers as credits through the Revenue Balancing Account ("RBA") Provision, so as to implement the earnings sharing percentages and procedures described herein, commencing on June 1 of the calendar year containing the Annual Evaluation Date and over the subsequent 12 months after June 1.

q) **Major Capital Projects Credits** shall be the amounts to be returned to customers through the Revenue Balancing Account Provision, to reduce the preceding year's RAM Revenue Adjustment (including interest at the rate described in the RBA Provision) for specific major capital projects that were not placed into service within the first nine months of the preceding RAM Period as expected. Because the Commission's review of the actual cost of Major Capital Projects may not occur until the rate case after these Major Capital Projects are included in one or more RAM Revenue Adjustment filings, Major Capital Projects Credits shall be used to refund to customers any prior collections (i.e., Return on Investment on Rate Base and Depreciation, plus interest) relating to the amount of Major Capital Projects costs that the Commission subsequently disallows for cost recovery. The Major Capital Projects Credits are to be refunded through the RBA Provision, commencing on June 1 of the calendar year containing the Annual Evaluation Date and over the subsequent 12 months after June 1.

Rate Adjustment Mechanism

The Company shall file with the Commission, the Consumer Advocate and each party to the Company's most recent rate case proceeding, the schedules specified below:

Evaluation Period Earnings Sharing:

REVISED SHEET NO. __
Effective January 1,2010

RATE ADJUSTMENT MECHANISM PROVISION

1. For the twelve month period ending December 31, of each year (the "Evaluation Period"), with the filing to be made no later than March 31, of the year following the conclusion of the Evaluation Period. The schedules will include the following:

   a) Company's recorded actual average net plant in service, accumulated deferred income taxes, inventory, working capital, and other rate base components. The schedules shall also show the utility's depreciation expense, operating and maintenance expense, income taxes, taxes other than income taxes, and other components of income for return, revenues, and capital structure, cost of debt, overall cost of capital, and return on common equity in the format set forth in the final order establishing the Company's latest effective rates.

   b) All applicable accounting and pro forma adjustments historically required in annual reports filed with the Commission.

   c) Pro-forma adjustments to remove from recorded revenues any out-of-period Earnings Sharing Revenue Credits or Major Capital Projects Credits recorded during the Evaluation Period, and

   d) A calculation comparing the achieved return on average common equity to the following earnings sharing grid, and indicating the Earnings Sharing Revenue Credit that should be recorded within the Revenue Balancing Account to effect the prescribed sharing of earnings above authorized levels:

REVISED SHEET NO. __
Effective January 1,2010

RATE ADJUSTMENT MECHANISM

ROE at or below the Authorized ROE	**Retained entirely by shareholders - no customer credits**
First 100 basis points (one percent) over Authorized ROE	**25% share credit to customers**
Next 200 basis points (two percent) over Authorized ROE	**50% share credit to customers**
All ROE exceeding 300 basis points (three percent) over Authorized ROE	**90% share credit to customers**

RAM Period RAM Revenue Adjustment:

2) The Company shall provide additional schedules indicating the following proposed RAM Revenue Adjustment calculations applicable for the RAM Period using the methodology set forth below:

   a) The Base Expenses shall be segregated between labor and non-labor amounts and treated as follows:
      i. The labor component shall be quantified for the RAM Period by application of the Labor Cost Escalation Rate, reduced to account for the Productivity Offset to labor expenses.
      ii. The Non-labor components quantified for the RAM Period by application of the Non-labor Escalation Rate.
      iii. Tracked O&M expenses for fuel, purchased power, pension/OPEBs, IRP/DSM or other rate adjustment provisions are to be carried forward for the RAM Period at the fixed amounts established in the most recent rate case proceeding.
   b) Depreciation and amortization expenses shall be quantified for the RAM Period by application of Commission-approved accrual rates to the actual recorded Plant in Service balances at the end of the Evaluation Period.

RATE ADJUSTMENT MECHANISM PROVISION

c) The Authorized Base Revenue required for Rate Base shall be determined by multiplying the applicable Return on Investment percentage rate times Rate Base. The Authorized Base Revenue associated with return on investment shall include related income taxes on the equity components of such return. The quantification of Rate Base is specified in greater detail in part (f) of this Section 2.
d) The Authorized Base Revenue impact of any Exogenous Tax Changes shall be included in the RAM Period calculation of Authorized Base Revenues.
e) Revenue taxes shall be adjusted to account for the change in parts (a) through (d) of this Section 2.
f) Rate Base for the RAM Period shall be quantified as follows:
    i. Plant in Service, Accumulated Depreciation, Accumulated Deferred Income Taxes and Contributions in Aid of Construction ("CIAC") shall be a two-point average of actual recorded balance sheet data at December 31 of the Evaluation Period, plus projected values at December 31 of the RAM Period determined as prescribed in parts (ii) through (v), below.
    ii. Plant in Service shall be quantified by adding to the recorded balances at December 31 of the Evaluation Period, the simple average of Baseline Capital Projects plant additions recorded in the immediately preceding five calendar years, plus the estimated cost of completed Major Capital Projects that are anticipated to be in service by September 30 of the RAM Period. The cost of Major Capital Projects shall be limited to the dollar amounts previously approved by the Commission.
    iii. Accumulated Depreciation at December 31 of the RAM Period shall be quantified by increasing the recorded balances at December 31 of the Evaluation Period by the amount set forth in Section 2 part (b) above.
    iv. CIAC shall be quantified by adding to the recorded balance at December 31 of the Evaluation

RATE ADJUSTMENT MECHANISM

Period an estimate of the net change for the RAM Period. The net change shall be based on a simple average of cash and in-kind CIAC for the immediately preceding five calendar years for programs (i.e., numerous low cost capital projects) plus specific engineering estimates of any contributions for the Major Capital Projects anticipated to be in service by September 30 of the RAM Period.

v. Accumulated Deferred Income Taxes shall be quantified by adding to the recorded balances at December 31 of the Evaluation Period the estimated tax effect of the depreciation timing difference (i.e., difference between book depreciation and tax depreciation) on the Baseline Capital Projects and Major Capital Projects added to rate base during the RAM Period.

vi. Working Cash and all other elements of rate base not specifically addressed above shall be fixed at the dollar amount approved by the Commission in the last rate case Decision & Order. These elements of rate base shall be held constant until revised by a Commission Decision & Order in a subsequent general rate case.

Evaluation Procedures

Complete, indexed workpapers and electronic files supporting the RAM Adjustment Schedules shall be provided to the Commission, the Consumer Advocate and all other parties to the Utility's most recent rate case proceeding, coincident with the date of filing. The Company will be prepared to provide supplemental information as may be requested to ensure adequate review by the Commission, Consumer Advocate or other parties. The Consumer Advocate and the other parties may propose any adjustments determined to be required to bring the schedules into compliance with the above provisions and will work collaboratively to reach agreement on any proposed

REVISED SHEET NO. __
Effective January 1, 2010

RATE ADJUSTMENT MECHANISM PROVISION

adjustments. As described in Sections 6-61-61 and 6-61-111 of the Hawaii Administrative Rules, Title 6, Chapter 61, based upon the Company's filed schedules and in the absence of any protests submitted by the Consumer Advocate or other parties not later than 15 days before the June 1 effective date of the RBA Rate Adjustments described in the RBA Provision tariff, the RBA Rate Adjustments incorporating the RAM Revenue Adjustment shall go into effect on the June 1 effective date and the Commission shall confirm in its monthly Tariff Order the effectiveness of the Company's proposed tariff, so as to achieve the revenue levels approved for both the Evaluation Period and RAM Period.

Notice

Notice of the annual Rate Adjustment Mechanism filing shall be provided to all affected customers of the Utility in accordance with the provisions of this section by publication in newspapers of general circulation within 30 days and by including notification with its billing statements within 60 days after the Company makes its annual filing pursuant to this tariff. The notice to customers shall include the following information:

a) A description of the proposed revision of revenues and Earnings sharing credits;

b) The effect of the proposed RAM Revenue Adjustment on the rates applicable to each customer class and on the typical bill for residential customers; and

c) The Company's address, telephone number and website where information concerning the proposed RAM Revenue adjustment may be obtained.

Sales Decoupling
Implications of customer outages on revenue

Under sales decoupling the utility recovers a target revenue amount to recover its fixed costs. Since target revenues are not linked to sales, customer outages will not affect the revenue recovered by the utility with decoupling. Under traditional ratemaking, in which utility revenues are tied to sales, customer outages reduce sales and reduce utility revenue.

The objective of sales decoupling is to allow the utility to recover its fixed costs. Fixed costs do not change as the result of customer outages. On the contrary, fixed costs may actually increase as a result of repair and replacement efforts necessary to restore the system following an outage.

In the HECO Companies' annual service reliability reports, reliability indices are calculated using the data from all sustained system outages, except customer maintenance outages. The indices' results are reported on a normalized basis, where the underlying data is scrubbed for outages that are occur due to "abnormal" situations such as hurricanes, tsunamis, earthquakes, floods, that cascade into a loss of load greater than 10% of the system peak load. Thus, there is a distinction between minor outages that are reflected in the annual service reliability reports and the major outages that are considered "abnormal".

The minor outages do not result in a great financial loss to the Companies, given their low level of occurrence as reflected in the annual service reliability reports. However, the Commission has initiated investigative proceedings for major outages when it has determined an investigation to be warranted. These investigations have addressed the cause of the outage, whether the outage was reasonably preventable by the Companies, if they could have been contained or made of shorter of duration, and if any penalties should be imposed. However, the Companies propose that in the event that the Commission finds that the Companies did not act responsibly, prudently, and in the public interest, the Commission may reduce the Companies' target revenues as an alternative to the imposition of a penalty.